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(54) Title: RIB-MOUNTED LOGGING-WHILE-DRILLING (LWD) SENSORS

(57) Abstract: A logging-while-Drilling method and apparatus for obtaining information about a formation uses a plurality of rib sets with pad-mounted sensor on one or more selectively non-rotating sleeves attached to a rotating housing that is part of a drilling assembly. The sensors may be density, neutron, NMR, resistivity, sonic, dielectric or any number of other sensors. In an alternative arrangement, the sensors rotate with the drill string.

Rib-Mounted Logging-While-Drilling (LWD) Sensors

FIELD OF THE INVENTION

This invention relates to the acquisition and processing of data acquired by a logging-while-drilling (LWD) tool during the drilling of a well borehole. More particularly, the invention relates to methods and devices for acquiring data downhole using sensors in contact with the borehole wall, processing the data and transmitting to the surface, in real-time, parameters of the formation penetrated by the borehole as the borehole is being drilled using LWD telemetry.

BACKGROUND OF THE INVENTION

Modern well drilling techniques, particularly those concerned with the drilling of oil and gas wells, involve the use of several different measurement and telemetry systems to provide petrophysical data and data regarding drilling mechanics during the drilling process. Data are acquired by sensors located in the drill string near the bit and either stored in downhole memory or transmitted to the surface using LWD telemetry devices.

A downhole device incorporating resistivity, gravity and magnetic measurements on a rotating drillstring is known in the art. A downhole processor uses the gravity and magnetic data to determine the orientation of the drill string, and using measurements from the resistivity device, makes measurements of formation resistivity at time intervals selected to

give measurements spaced around the borehole. These data are compressed and transmitted uphole by a mud pulse telemetry system. The depth of the resistivity sensor is computed at the surface and the data are decompressed to give a resistivity image of the face of the borehole wall with an azimuthal resolution of 30° or better.

Methods using the known apparatus described above methods are limited to making resistivity measurements in the subsurface and fail to address the issue of other useful measurements that could be made using a logging-while drilling (LWD) device. LWD is similar to methods known as measurement-while-drilling (MWD), and any reference herein to LWD is intended to include MWD, as an alternative embodiment.

The devices described above are also limited to measurement devices that rotate with the drill string and do not take advantage of current drilling methods wherein a mud motor is used and the drill bit could be rotating at a different speed from the drill string or wherein a non-rotating sleeve may be available on which substantially non-rotating measuring devices could be located. The present invention overcomes these inadequacies.

SUMMARY OF THE INVENTION

The present invention is an apparatus and method of making measurements of a plurality of parameters of interest of the formation

surrounding a borehole while a drillstring with a bit at an end thereof is drilling the borehole. In one aspect of the invention, a plurality of selectively non-rotating sleeves are mounted on the drillstring. One or more extendable ribs are mounted on each of the sleeves. Pads are coupled to each rib and sensors are coupled to each pad. When the ribs are extended, measurements of the parameters are made as the drillstring advances through the formation.

In another aspect of the invention, each of a plurality of non-rotating sleeves includes one or more non-extendable (fixed) ribs with pad-mounted sensors coupled thereto. The sensors on the fixed ribs include at least one of a neutron sensor and a density sensor. Other additional sensors may also be used.

In another aspect of the invention an extendable rib and a plurality of fixed ribs are disposed about the outside of a non-rotating sleeve to define a rib set. Each rib of the rib set includes a pad and a plurality of sensors coupled thereto. A plurality of rib sets are mounted on a single non-rotating sleeve, or one rib set may be mounted on each of a plurality of non-rotating sleeves.

In another aspect of this invention, an extendable rib or plurality of extendable ribs are disposed the outside of a subassembly (or sub) that is part of the drill string. As the drillstring rotates the ribs rotate. Each rib

contains a pad and a plurality of sensors. The subassembly is provided with sensors that enable the relative position of each rib to be determined with reference to a direction or gravitational orientation.

In another aspect of the invention, the drill bit is mounted on a rotating drillstring and the downhole assembly is provided with sensors that rotate with the drillstring to make measurements of the parameters of interest. The assembly is provided with magnetic, gravitational and/or inertial sensors to provide information on the orientation of the measurement sensors. A telemetry system sends information downhole about the depth of the drilling assembly. A processor downhole combines the depth and azimuth information with the measurements made by the rotating sensors, uses redundancy in the data to improve S/N ratio, compresses the data and sends it uphole by a telemetry system or stores it downhole for later retrieval.

In another aspect of the invention, the drill bit is driven by a downhole drilling motor. The motor may be on a rotating drillstring or on coiled tubing. The sensors for measuring the parameters of interest could be rotating with the drill bit. Alternatively, the sensors could have one of several configurations. In one configuration, the sensors are mounted on a substantially non-rotating sleeve; in another configuration, the sensors are mounted on pads and the pads are coupled to ribs that could be rotating or non-rotating, the pads being hydraulically or mechanically

actuated to make contact with the borehole wall. In any of these arrangements, the downhole assembly is provided with sensors that make measurements of the parameters of interest. The assembly is provided with magnetic, gravitational and/or inertial sensors to provide information on the orientation of the measurement sensors. A telemetry system sends information downhole about the depth of the drilling assembly. A microprocessor downhole combines the depth and azimuth information with the measurements made by the rotating sensors, uses redundancy in the data to improve S/N ratio, compresses the data and sends it uphole by a telemetry system. The parameters of interest include resistivity, density, compressional and shear wave velocity and structure, dipmeter, dielectric constant, acoustic porosity, NMR properties and seismic images of the formation.

In another aspect of the invention, the drill bit is adapted to function as a resistivity sensor. A current is generated by a first toroid. The current flows through the tool assembly, drill bit and formation. Current in a second toroid is generated by the current flowing through the tool and a resistivity is determined from current in the second toroid.

As a backup to, or independently of, obtaining the depth information by downhole telemetry, the present invention also provides a capability in the downhole microprocessor to use measurements from sensors at more than one depth to provide a rate of penetration. Surface-

measured depths can also be integrated with the measurements from the sensors using a surface mounted depth tracking system on a drilling rig.

BRIEF DESCRIPTION OF THE FIGURES

FIG. 1 is a schematic illustration of a drilling system.

FIG. 2 illustrates a drilling assembly for use with a surface rotary system for drilling boreholes wherein the drilling assembly has a non-rotating sleeve for effecting directional changes downhole.

FIG. 3A illustrates an arrangement wherein each of two independent non-rotating sleeves includes a rib set comprising an extendable rib and one or more fixed ribs.

FIG. 3B illustrates an arrangement wherein a single non-rotating sleeve includes two rib sets, each rib set comprising an extendable rib and one or more fixed ribs.

FIG. 3C illustrates an alternative embodiment of the single non-rotating sleeve arrangement of **FIG. 3B**.

FIG. 3D-3E illustrate alternative arrangements of resistivity sensors on a pad.

FIG. 3F illustrates the overlap between pads on a rotating sensor arrangement.

FIG. 3G illustrates an arrangement of density sensors according to the present invention.

FIG. 3H illustrates an arrangement of offset density and neutron sensors according to the present invention.

FIG. 3I illustrates the arrangement of elastic transducers on a pad.

FIG. 3J shows an embodiment of the present invention wherein the drill bit is used as an electrode for resistivity measurements.

FIG. 3K shows an alternative embodiment of the present invention.

FIGS. 3L-3M are cross section views of the tool of **FIG. 3K**.

FIG. 4 illustrates the acquisition of a set of reverse VSP data according to the present invention.

FIGS. 5A- 5B show a method by which depth is calculated downhole..

FIG. 6A and **6B** are schematic illustrations of the sequence of data flow in processing the data.

DETAILED DESCRIPTION OF THE INVENTION

FIG. 1 shows a schematic diagram of a drilling system **10** having a drilling assembly **90** shown conveyed in a borehole **26** for drilling the wellbore. The drilling system **10** includes a conventional derrick **11** erected on a floor **12** which supports a rotary table **14** that is rotated by a prime mover such as an electric motor (not shown) at a desired rotational speed. The drill string **20** includes a drill pipe **22** extending downward from the rotary table **14** into the borehole **26.** The drill bit **50** attached to the end of the drill string breaks up the geological formations when it is rotated to drill the borehole **26.** The drill string **20** is coupled to a drawworks **30** via a Kelly joint **21**, swivel, **28** and line **29** through a pulley **23.** During drilling operations, the drawworks **30** is operated to control the weight on bit, which is an important parameter that affects the rate of

penetration. The operation of the drawworks **30** is well known in the art and is thus not described in detail herein. A depth tracking system **S4** is well known in the art and is shown coupled to the drawworks **30**.

During drilling operations, a suitable drilling fluid **31** from a mud pit (source) **32** is circulated under pressure through the drill string by a mud pump **34.** The drilling fluid passes from the mud pump **34** into the drill string **20** via a desurger **36**, fluid line **38** and Kelly joint **21.** The drilling fluid **31** is discharged at the borehole bottom **51** through an opening in the drill bit **50.** The drilling fluid **31** circulates uphole through the annular space **27** between the drill string **20** and the borehole **26** and returns to the mud pit **32** via a return line **35.** A sensor $\mathbf{S_1}$ preferably placed in the line **38** provides information about the fluid flow rate. A surface torque sensor $\mathbf{S_2}$ and a sensor $\mathbf{S_3}$ associated with the drill string **20** respectively provide information about the torque and rotational speed of the drill string. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drill string **20.**

In one embodiment of the invention, the drill bit **50** is rotated by only rotating the drill pipe **52.** In another embodiment of the invention, a downhole motor **55** (mud motor) is disposed in the drilling assembly **90** to rotate the drill bit **50** and the drill pipe **22** is rotated usually to supplement the rotational power, if required, and to effect changes in the drilling direction.

The mud motor **55** is coupled to the drill bit **50** via a drive shaft (not shown) disposed in a bearing assembly **57.** The mud motor rotates the drill bit **50** when the drilling fluid **31** passes through the mud motor **55** under pressure. The bearing assembly **57** supports the radial and axial forces of the drill bit. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

In one embodiment of the invention, a drilling sensor module **59** is placed near the drill bit **50.** The drilling sensor module contains sensors, circuitry and processing software and algorithms relating to the dynamic drilling parameters. Such parameters preferably include bit bounce, stick-slip of the drilling assembly, backward rotation, torque, shocks, borehole and annulus pressure, acceleration measurements and other measurements of the drill bit condition. The drilling sensor module processes the sensor information and transmits it to the surface control unit **40** via a suitable telemetry system **72.**

FIG. 2 shows a schematic diagram of a rotary drilling assembly **255** conveyable downhole by a drill pipe or coiled tube (not shown). The drilling assembly **255** includes a device for changing drilling direction without stopping the drilling operations for use in the drilling system **10** shown in **FIG. 1.** The drilling assembly **255** has an outer housing **256** with an upper joint **257a** for connection to the drill pipe (not shown) and a lower joint **257b** for accommodating the drill bit **55.** During drilling operations,

the housing **256**, and thus the drill bit **55**, rotate when the drill pipe is rotated by the rotary table at the surface. The lower end **258** of the housing **256** has reduced outer dimensions **258** and bore **259** therethrough. The reduced-dimensioned end **258** has a shaft **260** that is connected to the lower end **257b** and a passage **261** for allowing the drilling fluid to pass to the drill bit **55.** A selectable non-rotating sleeve **262** is disposed on the outside of the reduced dimensioned end **258**, in that when the housing **256** is rotated to rotate the drill bit **55**, the non-rotating sleeve **262** remains in its position when selected (engaged) or rotates with the housing **256** when not selected (disengaged). There are several mechanisms known in the art for engaging and disengaging a tool member and thus not shown or described in detail herein. One or more independently adjustable extendable ribs **263a** are disposed on the outside of the non-rotating sleeve **262.** Each extendable rib **263a** is preferably hydraulically operated by a control unit in the drilling assembly **255.** Those versed in the art would also recognize that these ribs, because they are provided with the ability for selectively extending or retracting during drilling operations, can also be used as stabilizers and for controlling the drilling direction. Mechanisms for extending the ribs **263a** could be operated by hydraulic, mechanical or electrical devices. Furthermore, the extendable ribs **263a** may be biased in an extended or in a retracted position. A commonly used mechanical biasing arrangement is to have the extendable ribs mounted on springs that keep the extendable ribs biased in an extended or retracted position. Such

devices would be familiar to those versed in the art.

Also disposed on the sleeve **262** are one or more fixed ribs **263b**. The term "fixed" as used herein with respect to ribs **263b** is defined as being mounted in a substantially immovable relationship in a radial direction with respect to the sleeve **262**. In a preferred embodiment there are two fixed ribs **263b** and one extendable rib **263a** making a rib set **265**. The ribs **263a** and **263b** comprising the rib set **265** are located on the sleeve **262** at substantially the same distance along the longitudinal axis of the sleeve and each rib is spaced substantially equally about the circumference of the sleeve **262** from other ribs in the set **265**. In preferred embodiments to be discussed in detail hereinafter, there are at least two rib sets disposed on the drilling assembly **255**.

Each rib **263a** and **263b** includes a pad **264** for making contact with the borehole wall. A plurality of formation sensors (not shown) is located on each of the pads **264. Illustrative** arrangements of the formation sensors are discussed below in reference to **FIGS. 3D- 3I.**

The drilling assembly **255** also includes a directional sensor **271** near the upper end **257a** and sensors for determining the temperature, pressure, fluid flow rate, weight on bit, rotational speed of the drill bit, radial and axial vibrations, shock and whirl. Without limiting the scope of the invention, the directional sensors **271** could be of the magnetic or

inertial type. The drilling assembly **255** may include a number of non-magnetic stabilizers **276** near the upper end **257a** for providing lateral or radial stability to the drill string during drilling operations in addition to the support provided by the ribs **263a** and **263b**. A flexible joint **278** is disposed between the section **280** and the section containing the non-rotating sleeve **262.** A control unit designated by **284** includes a control circuit or circuits having one or more processors. The processing of signals is performed generally in the manner described below in reference to **FIG. 5A-5B**. A telemetry device, in the form of an electromagnetic device, an acoustic devise, a mud-pulse device or any other suitable device, generally designated herein by **286** is disposed in the drilling assembly at a suitable place. A microprocessor **272** is also disposed in the drilling assembly at a suitable location.

Referring now to **FIG. 3A**, the drilling assembly described above and shown in **FIG. 2** preferably includes two rib sets **365a** and **365b**. **FIG. 3A** illustrates an arrangement wherein the two rib sets **265a** and **265b** are coupled to two independent non-rotating sleeves **262a** and **262b**. Shown are the drilling shaft **260** with two non-rotating sleeves **262a** and **262b** mounted on the shaft **260**. A plurality of ribs **263a** and **263b** with sensors **301** are attached to each sleeve **262.** In an exemplary embodiment, each rib set **265a** and **265b** comprises a selectively extendable rib **263a** and one or more fixed ribs **263b**. Each rib **263a** and **263b** has a pad **264** coupled thereto. Each pad **264** has a sensor **301** for measuring a

parameter of interest. The combination of a pad **264** and sensor **301** is also called a pad-mounted sensor. The mechanism for moving the extendable rib **263a** out toward the borehole, whether it be hydraulic, a spring mechanism or another mechanism is not shown. In this arrangement, the two non-rotating sleeves **262a** and **262b** are independently controllable in that each sleeve can be engaged or disengaged without affecting the operation of the other sleeve. Likewise, the selectively extendable rib **263a** on one sleeve **262a** can be extended or retracted without affecting (or being affected by) the position of the selectively extendable rib 263a coupled to the second sleeve **262b**.

In one embodiment, two toroids **305** that are wound with a current carrying conductor (not shown) surround the shaft **260**. The toroids are arranged with same polarity, so that upon passage of a current in the toroid **305**, a circumferential magnetic field is induced in the two toroids **305**. This magnetic field, in turn, induces an electric field along the axis of the shaft **260**. The leakage current measured by at least one of the sensors **301** is then a measure of the resistivity of the formation adjacent to the sensors, with the leakage current being substantially radial. Such an arrangement has been used before in wireline logging but has not been attempted before in measurement while drilling applications. The shaft **260** is provided with stabilizer ribs **303** for controlling the direction of drilling.

In a preferred embodiment, the sensors **301** on the extendable rib **263a** of the first rib set **265a** are resistivity sensor (buttons) while the sensor on at least one of the fixed ribs **263b** of the first rib set **265a** is a density sensor. The sensors **301** of the second rib set **265b** include a neutron sensor on at least one fixed rib **263b** and resistivity sensors on the extendable rib **263a**.

In an alternative embodiment, all rib-mounted sensors are of the same type. The specific application controls the selection of sensor type. For example, one application may require resistivity sensors while another application requires another sensor technology.

Figure 3B illustrates an alternative embodiment wherein rib-mounted sensors are coupled to a single non-rotating sleeve **262c**. This single-sleeve arrangement provides fixed positioning of the ribs **263a** and **263b** of the first rib set **265a** relative to the ribs **263a** and **263b** of second rib set **265b**. This arrangement provides a simpler design and reduces the need to calculate or measure the position of the sensors **301** relative to each other. The embodiment shown includes a rotatable shaft **260** having a single long non-rotating sleeve **262c** coupled to the shaft **260** at a reduced dimensioned section similar to the embodiment described above and shown in **FIG. 2**. A first rib set **265a** comprising a selectively extendable rib **263a** is coupled to the sleeve **262c**. A pad **264** suitable for maintaining sliding contact with a borehole is coupled to the extendable

rib **263a**. One or more sensors **301** are operatively associated with the pad **264**. The first rib set **265a** further includes one or more fixed ribs **263b** coupled to the sleeve **262c**. The fixed ribs **263b** include pads **264** substantially identical to the pad of the extendable rib. Sensors **301** are coupled to the pads 264 of the fixed ribs **263b**. These fixed-rib sensors may be the same or different as the sensors on the pads of the extendable rib **263a**.

A second rib set **265b** is coupled to the single non-rotating sleeve **262c** longitudinally spaced apart from the first rib set **265a**. The second rib set **265b** includes a selectively extendable rib **263a** coupled to the sleeve **262c**. A pad **264** suitable for maintaining sliding contact with a borehole is coupled to the extendable rib **263a**. One or more sensors **301** are operatively associated with the pad **264**. The second rib set **265b** further includes one or more fixed.ribs **263b** coupled to the sleeve **262c**. The fixed ribs **263b** include pads **264** substantially identical to the pad of the extendable rib. Sensors **301** are coupled to the pads **264** of the fixed ribs **263b**. These fixed-rib sensors may be the same or different as the sensors on the pads of the extendable rib **263a**.

In a preferred embodiment, the sensors **301** on the extendable rib **263a** of the first rib set **265a** are resistivity sensor (buttons) while the sensor on at least one of the fixed ribs **263b** of the first rib set **265a** is a density sensor. The sensors **301** of the second rib set **265b** include a

neutron sensor on at least one fixed rib **263b** and resistivity sensors on the extendable rib **263a**.

When extended, the extendable ribs **263a** in the embodiments described above and shown in **FIGS. 3A** and **3B** may function as steering members or stabilizers, although stabilizers **303** may be coupled to the shaft **260** to aid in stabilizing the shaft during drilling operations. In the illustrative embodiment of **FIG. 3B**, one or more current carrying toroids **305** are operatively coupled to the shaft **260** at the reduced dimensioned section to produce an electric field that operates in the same manner as in the discussion above with respect to **Fig. 3A**.

FIG. 3C illustrates and alternative embodiment of the single non-rotating sleeve arrangement of **FIG. 3B**. Shown is a subassembly or ("sub") **800** suitable for operation with a rotary drilling assembly such as described above and shown in **FIG. 2**. The sub **800** is conveyable downhole by drill pipe (not shown). A typical drillpipe compatible connection **1201** is coupled to each end of the sub **800**. Each connector is adapted for the transfer of power and data between the sub **800** and components located elsewhere along the drilling assembly. An external power source (not shown) is preferably used with this arrangement to provide power to the sub **800**. This source can be either the rotary drilling assembly or a separate LWD assembly.

The sub **800** includes a reduced dimension shaft **1202**, between the connections **1201**. A passage **261** allows drilling fluid to flow internally through the sub **800** from a drillpipe connected at the connection **1201**. A selectively non-rotating sleeve **1203** is coupled to the shaft **1202**. The sleeve **1203** is substantially identical to the non-rotating sleeve described above and shown in **FIG 3B**. A plurality of rib sets **265a** and **265b** are mounted on the sleeve **1203**. The rib sets **265a** and **265b** are substantially identical to the rib sets described above and shown in **FIGS. 3A and 3B**. Each rib set comprises an extendable rib **263a** having a pad **264** and a plurality of sensors **301** mounted thereon. Each rib set **265a** and **265b** also includes one or more fixed ribs **263b**, wherein each fixed rib **263b** includes a pad **264** and sensors **301**. Two toroids **305** are disposed on the sleeve **1203** at suitable locations near the joints **1201**. Each toroid is wound with a current carrying conductor (not shown) such that current flowing in a toroid is measured by one or more of the sensors **301**.

The pads **264** can contain a plurality of formation evaluation sensors mounted on each pad in addition or separate to the sensors that could measure the current field generated by the toroids. The pads **264** coupled to the extendable ribs **263a** can be extended to contact the borehole wall by various hydraulic or mechanical devices either automatically or on command from an external source, or the extendable ribs **263a** may be retracted so that the pads **264** do not contact the

borehole wall.

The sub **800** includes communication, data processing and transfer software and electronic hardware not shown in the figure. These components may be located on the sleeve **1203** of at any suitable location on the sub **800**. The software/hardware includes a storage device to store raw, or processed data for later independent access by external computers. The sub **800** further includes software and hardware for performing self diagnostic routes to determine the correct performance of the sub.

The ribs **263a** and **263b** are coupled to the sleeve in a detachable relationship to allow for easy reconfiguration of sensors **301**. The sensors **301** can be removed from the corresponding pad **264** for inspection and repair or replacement with other sensors.

Figure 3C shows a particularly useful configuration wherein two rib sets **265a** and **265b** are separated from each other along a non-rotating sleeve **1203**. The ribs of the first set **265a** are offset with respect to the ribs of the second set **265b** as shown. This configuration enables imaging around-the-borehole. Additional sensors like laterolog type resistivity and circumferentional borehole acoustic imaging mounted to the sleeve **1203** in a suitable location **1204** such as between the two rib sets **265a** and **265b**. Pad orientation is determined using sensors and a processor (not shown) as described above and shown in **FIG. 2** to provide azimuthal and

borehole orientation data.

An alternative arrangement to this configuration is the addition of a mechanism that allows the non rotating sleeve **1203** to rotate with the shaft **1202** at relative speeds ranging from non-rotating to rotating at the same speed as the shaft.

Still referring to **FIG. 3C**, the sub **800** may include electromagnetic induction sensors used to determine the resistivity of the formation. An electromagnetic transmitter antenna **1050** is used to induce an electromagnetic signal into the formation. The antenna **1050** is coupled to the non-rotating sleeve **1203**. One or more sensors **301** are selected from known electromagnetic receiver modules. The electromagnetic sensors **301** are coupled to the extendable rib **263a** of at least one rib set **265b**. Each electromagnetic receiver module **301** has a plurality of slots **1056** behind which receiver coils (not shown) are disposed. The slots are axially spaced apart so that measurements may be made from at least two transmitter to receiver distances. The antenna **1050** is controlled by an electronics module **1052** disposed at a suitable location. Using known electromagnetic induction logging methods, the transmitter sends out a pulse at a frequency and the amplitude and phase of the signal received by the receivers in the receiver modules is used to determine the resistivity of the formation. The frequency of the transmitted signal is typically between 1MHz and 10 MHz.. With the azimuthally disposed

arrangement of the extendable ribs **263a** and the receiver modules **301** on the ribs **263a**, this embodiment makes it possible to determine an azimuthal variation of resistivity. When multiple frequency signals are used, both the resistivity and the dielectric constant of the formation may be determined using known methods. The sensor configuration just described and shown in **FIG. 3C** may also be used with the embodiments described above and shown in **FIG. 3A and 3B**.

In another embodiment of the invention, induction measurements are obtained using an electrode arrangement according to **FIG. 3D**. For example, referring to **Fig 3D,** the electrodes **301aa, 301ab** could be used as a transmitter when pulsed simultaneously, as could the electrodes **301da, 301db**. Similarly, the electrodes **301ba, 301bb** constitute one receiver while the electrodes **301ca, 301cb** constitute a second receiver.

FIGS. 3D and 3E illustrate alternative arrangements for a plurality of resistivity sensors on a single pad **264.** The electrodes are arranged in a plurality of rows and columns. In **FIG. 3D**, two columns and four rows are shown, with the electrodes identified from **301aa** to **301db**. In **FIG. 3E**, four rows of electrodes **301ca - 301fc** are shown. Each row is offset with the rows above and below it by, for example, one half the distance separating the electrodes along a row. In a typical arrangement, the electrodes would be an inch apart. Having a plurality of columns increases the azimuthal resolution of resistivity measurements while

having a plurality of rows increases the vertical resolution of resistivity measurements.

FIG 3F illustrates how a plurality of pads, six in this case, can provide resistivity measurements around the borehole. In the figure, the six pads are shown as **264** at a particular depth of the drilling assembly. For illustrative purposes, the borehole wall has been "unwrapped" with the six pads spread out over 360° of azimuth. As noted above, the pads are on arms that extend outward from the tool body to contact the wall. The gap between the adjacent pads will depend upon the size of the borehole: in a larger borehole, the gap will be larger. As the drilling proceeds, the tool and the pads will move to a different depth and the new position of the pads is indicated by **264.** As can be seen, there is an overlap between the positions of the pads in azimuth and in depth. The tool orientation is determined by the microprocessor **272** from the directional sensors **271.** This overlap provides redundant measurements of the resistivity that are processed as described below with reference to **FIG. 5A** and **5B**.

Those versed in the art would recognize that even with a substantially non-rotating sleeve on the drilling assembly, some rotation of the sleeve will occur. With a typical drilling rate of 60 feet per hour, in one minute, the tool assembly will advance one foot. With a typical rotary speed of 150 rpm, even a sleeve designed to be substantially non rotating

could have a complete revolution in that one minute, providing for a complete overlap. Those versed in the art would also recognize that in an alternate disposition of the sensor that rotates with the drill bit, a complete overlap would occur in less than one second.

FIG. 3G illustrates an arrangement of density sensors according to the present invention. Shown is a cross section of the borehole with the wall designated as **326** and the tool generally as **258.** All pads are shown engaging the wall of the borehole. This arrangement is similar to that used in wireline tools except that in wireline tools, the source is located in the body of the tool.

FIG. 3H illustrates an arrangement of sensors according to the present invention such as described above and shown in **FIG. 3C**. Shown is a cross section of the borehole with the wall designated as **326** and the tool generally as **258.** A first set **265a** of ribs **263a** and **263b** are represented as shown with solid lines, and a second set **265b** of ribs **263a** and **263b** are represented as shown with dashed lines. The first set **265a** being offset with respect to the second set **265b**. The offset of the ribs is preferably selected such that the sensors on the extendable ribs **263a** are positioned toward opposite walls of the borehole **326**. The pads are shown engaging the wall of the borehole.

The arrangements of **FIGS. 3G** and **3H** illustrate a logging-while-

sliding method according to the present invention. These embodiments, as those of **FIGS. 3A-3C** above enable continuous contact with the borehole wall as the drilling assembly traverses the formation. The sensors may be maintaining a substantially straight path along the wall when the non-rotating sleeve is engaged (not rotating with the shaft). The sensors may also be traveling a helical path along the wall when the sleeve is disengaged (rotating with the shaft).

In an alternative arrangement the pads could have elastic (commonly referred to as acoustic) transducers mounted on them. In the simplest arrangement shown in **FIG. 3I**, each pad has a three component transducer (or, equivalently, three single component transducers) mounted thereon. The transducer is adapted to engage the borehole wall and capable of pulsating or vibrating motion in three directions, labeled as **465a, 465b** and **465c**. Those versed in the art would recognize that each of these excitations generates compression and shear waves into the formation. Synchronized motion of transducers on the plurality of pads introduces seismic pulses of different polarization into the formation that can be detected at other locations. In the simplest configuration, the detectors are located on the surface (not shown) and can be used for imaging the subsurface formations of the earth. Depending upon the direction of the pulses on the individual pads, compression and polarized shear waves are preferably radiated in different directions.

FIG. 3J illustrates an alternative embodiment having sensors on extendable ribs **263a** coupled to a non rotating sleeve **262d**. In this configuration the pads **264** are instrumented with resistivity or alternative sensors as described above. The drill bit **55** is adapted to function as an electrode to give a resistivity reading at the bit.

A current is driven by a known voltage through a toroid **1206.** The current flowing in the toroid **1206** induces a voltage along the collar **2576**. The voltage on the collar **2576** sets up current in the formation near the drill bit **55**. The current flows through the formation, drill bit **55** and collar **2576**. A receiver coil **1207**, near the bottom of the tool measures the current flowing in the tool. Knowing the voltage, the bit resistivity is determined by measuring the current using methods described herein.

Referring now to **FIG. 3K**, the extendable ribs that contain the pad based sensors are housed within a drillstring subassembly **800**. A single or multiple number of ribs **263a** are contained within the body of this sub. Each rib contains a pad **264** mounted with a plurality of sensors **301**. The sub **800** is conveyed downhole by drillpipe. At each end of the sub is a drillpipe compatible connection **1201**. Each connection is adapted for the transfer of power and data between the sub and components of the LWD system located elsewhere in the drillstring. A power source external to

The extendable ribs extend on command from the external LWD assembly or from a microprocessor within the sub (not shown) as a response to the start of rotation or as a response to a command initiated independently of rotation. When rotation stops the ribs will retract back into the sub as a response to the cessation of rotation or as a response to a command initiated independently of rotation.

FIGS. 3L and **3M** show a cross section through sub **800**. **Fig. 3L** shows the extendable rib **263a** with the pad **264** and sensors **301** extended to contact the borehole wall. **FIG. 3M** shows the extendable rib retracted into the housing of the sub.

The orientation of the sensor packages on each extendable rib is referenced to a number of components (not shown) either within the sub or external to the sub in the LWD system that measure orientation and direction of the drilling assembly.

FIG. 4 illustrates the acquisition of a set of reverse VSP data according to the present invention. A plurality of seismic detectors **560** are disposed at the surface **510.** A borehole **526** drilled by a drill bit **550** at the end of a drillstring **520** is shown. The downhole drilling assembly includes seismic sources **564** on pads that engage the walls of the borehole. Seismic waves **570** radiating from the sources **564** are reflected by boundaries such as **571** and **573** and detected at the surface

by the detectors **560.** The detection of these at the surface for different depths of the drilling assembly gives what is called a reverse Vertical Seismic Profile (VSP) and is a powerful method of imaging formations ahead of the drill bit. Processing of the data according to known methods gives a seismic image of the subsurface. While reverse VSPs using the drill bit itself as a seismic source have been used in the past, results are generally not satisfactory due to a lack of knowledge of the characteristics of the seismic signal and due to poor S/N ratio. The present invention, in which the source is well characterized and is in essentially the same position on a non-rotating sleeve has the ability to improve the S/N ratio considerably by repeatedly exciting the sources in essentially the same position. Those versed in the seismic art would be familiar with the pattern of energy radiated into the formation by the different directions of motions of the transducers **465** and their arrangement on a circular array of pads.

Those versed in the art would also recognize that instead of seismic pulses, the seismic transmitters could also generate swept-

The VSP configuration could be reversed to that of a conventional VSP, so that downhole sensors on a non-rotating sleeve measure seismic signals from a plurality of surface source positions. Such an arrangement would suffer from the disadvantage that a considerably greater amount of data would have to be transmitted uphole by telemetry.

In an alternate arrangement (not shown), two sets of axially spaced-apart pads are provided on the non-rotating sleeve. The second set of pads is not illustrated but it has an arrangement of detectors that measure three components of motion similar to the excitation produced by the sources **465.** Those versed in the art would recognize that this gives the ability to measure compressional and shear velocities of the formation between the source and the receiver. In particular, because of the ability to directly couple a seismic source to the borehole wall, shear waves of different polarization can be generated and detected. Those versed in the art would know that in an anisotropic formation, two different shear waves with different polarization and velocity can be propagated (called the fast and the slow shear wave). Measurement of the fast and slow shear velocities gives information about fracturing of the formation and would be familiar to those versed in methods of processing the data to obtain this fracturing information.

The same arrangement of having seismic transmitters and receivers on non-rotating pads in the drilling assembly makes it possible

to record reflections from surfaces in the vicinity of the borehole. In particular, it enables the device to obtain distances to seismic reflectors in the vicinity of the borehole. This information is useful in looking ahead of the drillbit and in guiding the drillbit where it is desired to follow a particular geologic formation.

Those versed in the art would recognize that by having an arrangement with four electrodes substantially in a linear arrangement on a number of non-rotating pads, the outer electrodes being a transmitter and a receiver respectively, and by measuring the potential difference between the inner electrodes, a resistivity measurement of the formation can be obtained. Such an arrangement is considered to be conventional in wireline logging applications but has hitherto not been used in measurement-while-drilling applications because of the difficulty in aligning the electrodes on a rotating drillstring.

The embodiments of the present invention discussed above include various sensors located on a non-rotating sleeve that is part of a drilling assembly which includes a downhole mud motor. Those versed in the art would recognize that an equivalent arrangement can be implemented wherein instead of a drillstring, coiled tubing is used. This arrangement is intended to be within the scope of the present invention.

In an alternate embodiment of the invention, the formation sensor

assembly could be directly mounted on the rotating drillstring without detracting from its effectiveness. This was discussed above with respect to resistivity sensors in **FIG. 3D**

The method of processing of the acquired data from any one of these arrangements of formation sensors is discussed with reference to **FIGS 5A- 5B**. For illustrative purposes, **FIG. 5A** illustrates the "unwrapped" resistivity data that might be recorded by a first resistivity sensor rotating in a vertical borehole as the well is being drilled. The horizontal axis **601** has values from 0° to 360° corresponding to azimuthal angles from a reference direction determined by the directional sensor **271.** The vertical axis **603** is the time of measurement. As the resistivity sensor rotates in the borehole while it is moved along with the drill bit, it traces out a spiral path. Indicated in **FIG 5A** is a sinusoidal band **604** corresponding to, say, a bed of high resistivity intersecting the borehole at a dipping angle.

In one embodiment of the invention, the downhole processor **272** uses the depth information from downhole telemetry available to the telemetry device **286** and sums all the data within a specified depth and azimuth sampling interval to improve the S/N ratio and to reduce the amount of data to be stored. A typical depth sampling interval would be one inch and a typical azimuthal sampling interval is 15^0 . Another method of reducing the amount of data stored would be to discard redundant samples within the depth and azimuth sampling interval. Those

versed in the art would recognize that a 2-D filtering of the data set by known techniques could be carried out prior to the data reduction. The data after this reduction step is displayed on a depth scale in **FIG 5B** where the vertical axis **605** is now depth and the horizontal axis **601** is still the azimuthal angle with respect to a reference direction. The dipping resistive bed position is indicated by the sinusoid **604'**. Such a depth image can be obtained from a time image if at times such as **607** and **609**, the absolute depth of the resistivity sensor, **607'** and **609'** were known.

As a backup or as a substitute for communicating depth information downhole, the microprocessor uses data from the additional resistivity sensors on the pads to determine a rate of penetration during the drilling. This is illustrated in **FIG 5A** by a second resistivity band **616** corresponding to the same dipping band **604** as measured at a second resistivity sensor directly above the first resistivity sensor. The spacing between the first and second resistivity sensors being known, a rate of penetration is computed by the microprocessor by measuring the time shift between the bands **604** and **616.** The time shift between the bands **604** and **606** could be determined by one of many methods, including cross-correlation techniques. This knowledge of the rate of penetration serves as a check on the depth information communicated downhole and, in the absence of the downhole telemetry data, can be used by itself to calculate the depth of the sensors.

The method of processing discussed above works equally well for resistivity measurements made by sensors on a non-rotating sleeve. As noted above with reference to **FIG. 3B**, there is still a slow rotation of the sensors that provides redundancy that can be utilized by the processor **272** as part of its processing-before-transmission.

FIG. 6A illustrates the flow of data in one embodiment of the invention. The plurality of azimuthal data sensors (**301** in **FIG. 3A**) are depicted at **701.** The output **701a** of the azimuthal data sensors **701** is azimuthal sensor data as a function of time. The direction sensors (**271** in **FIG. 2**) are denoted at **703.** The output **703a** of the direction sensors **703** is the azimuth of the drilling assembly as a function of time. Using timing information **705a** from a clock **705** and the information **709a** from the drilling ahead indicator **709**, the processor first carries out an optional data decimation and compression step at **707.** The drilling ahead indicator uses a plurality of measurements to estimate the rate of advance of the drill bit. A sensor for measuring the weight on the drill bit gives measurements indicative of the rate of penetration: if the weight on the drill bit is zero, then the rate of penetration is also zero. Similarly, if the mud flow indicator indicates no flow of the mud, then too the drill bit is not advancing. Vibration sensors on the drill bit also give signals indicative of the forward movement of the drill bit. A zero value for weight on the drill bit, mud flow or drill bit vibration means that the sensor assembly is at a constant depth.

This step of data decimation and compression may stack data from multiple rotations of the sensor assembly that fall within a predetermined resolution required in the imaging of the data. This information **707a** consisting of data as a function of azimuth and depth is stored in a memory buffer **711.** A memory buffer with 16 MByte size is used, adequate to store the data acquired using one segment of drill pipe. As would be known to those versed in the art, the drill pipe comes in segments of 30 feet, successive segments being added at the wellhead as drilling progresses.

Using estimates of the drilling speed from **717**, and a drilling section completed indicator **713** a depth - time correlation is performed **715.** The drilling section completed indicator includes such information as the number of drill string segments. The drilling rate estimate is obtained, e.g., from the method given in the discussion of **FIGS. 5A** and **5B** above. The time-depth transformation function **715a** obtained by this is used at **719** to process the data as a function of azimuth and time in the memory buffer **711** to give an image that is a function of azimuth and depth. This image is stored downhole at **721** in a memory buffer. With 16 Mbytes of memory, it is possible to store 1700 feet of data downhole with a 1 inch resolution. This data is later retrieved when tripping the well or could be transmitted uphole using the telemetry device **286.** By processing the data downhole in this fashion, the demand on the telemetry device is greatly reduced and it can be used for transmitting other data relating to

the drilling motor and the drill bit uphole.

The arrangement shown in **FIG. 6A** does not use any telemetry data from the surface to compute depth. In an alternate arrangement shown in **FIG. 6B,** a depth calculation is performed downhole at **759** to give an actual position of the sensor assembly using information from a number of sources including telemetry data. One is the timing information **755a** from the clock **755**. A drilling speed sensor gives an indication of the drilling speed. Drilling speed **756a** is obtained from one of two sources **756.** In one embodiment, a downhole inertial sensor (not shown) is initialized each time that drilling is stopped for adding a section of drill pipe. The information from this inertial sensor provides an indication of drilling speed. In addition, or as an alternative, drilling speed transmitted from the surface by the downlink telemetry could be used and received at the downhole telemetry device **286** is used.

An indicator of the drilling section completed **761**, as discussed above with reference to **713** in **FIG. 6A** is used as an additional input for the depth calculations, as is an estimate from the drilling ahead indicator **763**, discussed above with reference to **709** in **FIG. 6A.** This depth calculation **759a** is used in data compression and decimation **757** (as discussed above with reference to **FIG. 6A**) to process data **751a** from the azimuthal measurement sensors **751** and the data **753a** orientation sensors **753.** The image processing at **765** gives the image data as a

function of depth **765a**, this data being stored downhole **767** with the same resolution as at **721** in **FIG. 6A**. The processing scheme of **FIG. 6B** does not require the memory buffer **711** that is present in **FIG. 6A**; however, it does require more depth data to be transmitted downhole, thus tying up the telemetry link to some extent.

As noted above in the discussion of **FIGS. 5A- 5B**, a combination of both methods could also be used, i.e. perform depth calculations from sensor data downhole in addition to using downlinked data.

The discussion above was with respect to resistivity measurements. Any other scalar measurement made by a sensor can be treated in the same fashion to improve the S/N ratio prior to transmitting it uphole by telemetry. Vector data, such as acquired by compressional and shear wave transducers requires somewhat more complicated processing that would be known to those versed in the art.

As mentioned above, the data transmitted from downhole is indicative of resistivities at uniformly sampled depths of layers of the formation. The data is transmitted in real time. The processes and apparatus described above provide a relatively high resolution color image of the formation in real-time. The resolution of this image may be enhanced even further by using various image enhancement algorithms. These image enhancing algorithms would be familiar to those versed in

the art.

The foregoing description has been limited to specific embodiments of this invention. It will be apparent, however, that variations and modifications may be made to the disclosed embodiments, with the attainment of some or all of the advantages of the invention. In particular, the invention may be modified to make density and acoustic measurements. Therefore, it is the object of the appended claims to cover all such variations and modifications as come within the true spirit and scope of the invention.

CLAIMS

What is claimed is:

1. A formation evaluation apparatus mounted on a drilling assembly including a drill bit for drilling a borehole in a formation, the apparatus being useful for determining a parameter of interest of the formation surrounding a borehole having a longitudinal axis created by the drilling assembly, the apparatus comprising:

(a) a rotatable housing;

(b) at least one selectable member on the outside of the housing, the member being a rotating member when not selected and a substantially non-rotating when selected; and

(c) at least one rib set mounted on the selectable member, the rib set comprising at least one selectively extendable rib having a first pad coupled thereto for making contact with the formation when the extendable rib is extended, the contact being substantially continuous as the drilling assembly traverses the formation, at least one fixed rib having a second pad coupled thereto for making contact with the formation, and a first formation evaluation sensor operatively coupled to the first pad for making a first measurement relating to the parameter of interest of the formation.

2. The apparatus of claim **1** further comprising a processor disposed in the housing, the processor using directional information from a directional sensor operably coupled to the housing and the measurement from one of the first and second formation evaluation sensors to determine the parameter of interest.

3. The apparatus of claim **1** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a jointed pipe, and (ii) coiled tubing.

4. The apparatus of claim **1** further comprising an extension device for moving the extendable rib from a retracted position to an extended position wherein the pad makes contact with the formation.

5. The apparatus of claim **4**, wherein the extension device is selected from a group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.

6. The apparatus of claim **1** wherein the at least one rib set is at least two rib sets comprising a first rib set and a second rib set, the first rib set further including a second formation evaluation sensor operatively coupled to the second pad for making a second measurement relating to the parameter of interest of the formation,

and the second rib set having a further including a third formation evaluation sensor operatively coupled to a third pad for making a third measurement relating to the parameter of interest of the formation.

7. The apparatus of claim **6** wherein the first formation evaluation sensor is a resistivity sensor, the second formation evaluation sensor is a neutron sensor and the third formation evaluation sensor is a density sensor.

8 The apparatus of claim **1** further comprising a first toroid and a second toroid, each toroid being coupled to the selectable member, the first toroid for causing a current to flow through the formation and the drill bit, the second toroid being responsive to the current flowing through the drill bit, and a processor for determining the resistivity of the formation, the determination being based on the current in the second toroid.

9 The apparatus of claim **1** wherein the pad is in contact with the formation and the member is not selected for sliding the pad along the formation in a substantially helical path.

10 The apparatus of claim **1** wherein the pad is in contact with the formation while the member is selected for sliding the pad along

the formation in a substantially straight path.

11 The apparatus of claim **1** wherein the at least one selectable member comprises at least two selectable members.

12. The apparatus of claim **2** wherein the parameter of interest is a resistivity image of the borehole.

13. A formation evaluation apparatus mounted on a drilling assembly for determining a parameter of interest of a formation surrounding a borehole, said apparatus comprising:

(a) a rotatable housing;

(b) a directional sensor operably coupled to the housing for making measurements related to the orientation of the housing;

(c) a telemetry device disposed in the housing, said telemetry device adapted to receive depth information from an uphole controller;

(d) at least one selectively rotatable formation evaluation sensor operatively coupled to the housing and on the outside thereof, said at least one formation evaluation sensor capable of contact with the formation to make measurements related to the parameter of interest, said at least one formation evaluation sensor being selectively

rotatable between a substantially non-rotating state and a rotating state; and

(e) a processor for determining the parameter of interest from the measurements made by the directional sensor, the depth information and the measurements made by the at least one formation evaluation sensor.

14. The apparatus of claim **13** wherein the telemetry device is further adapted to transmit the determined parameter of interest to the uphole controller.

15. The apparatus of claim **13** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a drillstring, and (ii) a coiled tubing.

16. The apparatus of claim **13** further comprising a selectable substantially non-rotating sleeve coupled to the housing, and wherein the at least one formation evaluation sensor is carried by the sleeve.

17. The apparatus of claim **13** further comprising a pad carrying the at least one formation evaluation sensor.

18. The apparatus of claim **13** further comprising an extension device

for moving the pad from a retracted position to an extended position wherein the pad makes contact with the formation, said device selected from the group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.

19. The apparatus of claim **13** wherein the parameter of interest is selected from the set consisting of: (i) resistivity of the formation, (ii) density of the formation, (iii) compressional wave velocity of the formation, (iv) fast shear wave velocity of the formation, (v) slow shear wave velocity of the formation, (vi) dip of the formation, and (vii) radioactivity of the formation, and (viii) resistivity image of the borehole.

20. The apparatus of claim **13** further comprising at least one stabilizer coupled to the housing for stabilizing the apparatus during drilling operations, and wherein the at least one formation evaluation sensor is carried by the at least one stabilizer.

21. A method of determining a parameter of interest of a formation surrounding a borehole while drilling the borehole, comprising:

(a) conveying in the borehole a drilling assembly including a drillbit for drilling the borehole and a formation evaluation apparatus including a rotatable housing;

(b) making measurements related to a parameter of interest of

the formation with a formation evaluation sensor, wherein the sensor is coupled to a pad carried on a selectable member on the outside of the housing, the selectable member being a rotating member when not selected and a substantially non-rotating member when selected; and

(c) processing the measurements from the formation evaluation sensor in a processor on the housing to determine the parameter of interest.

22. The method of claim **21** further comprising obtaining directional information from a directional sensor coupled to the housing and using the directional information in the processor.

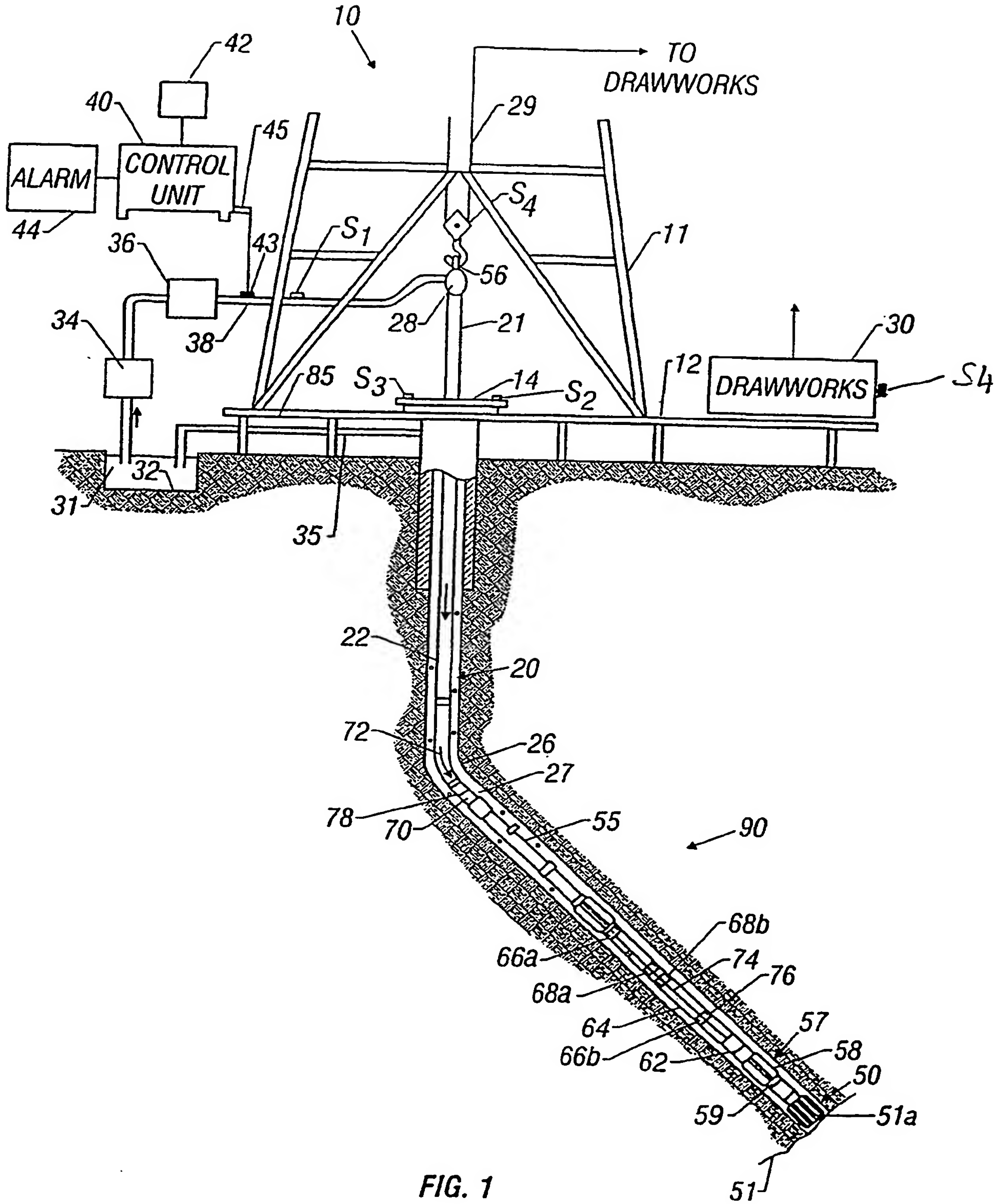
23. The method of claim **22** wherein the processing includes computing a rate of penetration of the drilling tool.

24. The method of claim **22** wherein the parameter of interest is a resistivity image of the borehole.

25. The method of claim **21** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a drillstring, and (ii) coiled tubing.

26. The method of claim **21** further comprising operating an extension

device for moving the pad from a retracted position to an extended position wherein the pad makes contact with the formation, said extension device selected from the group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.


10
TO
DRAWWORKS
42
40
CONTROL UNIT
ALARM
44
45
29
S_4
S_1
43
11
36
56
28
21
34
38
30
DRAWWORKS
S_4
12
85
S_3
14
S_2
32
31
35
22
20
72
26
27
78
70
55
90
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66a
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68a
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57
66b
62
58
50
59
51a
51

FIG. 1

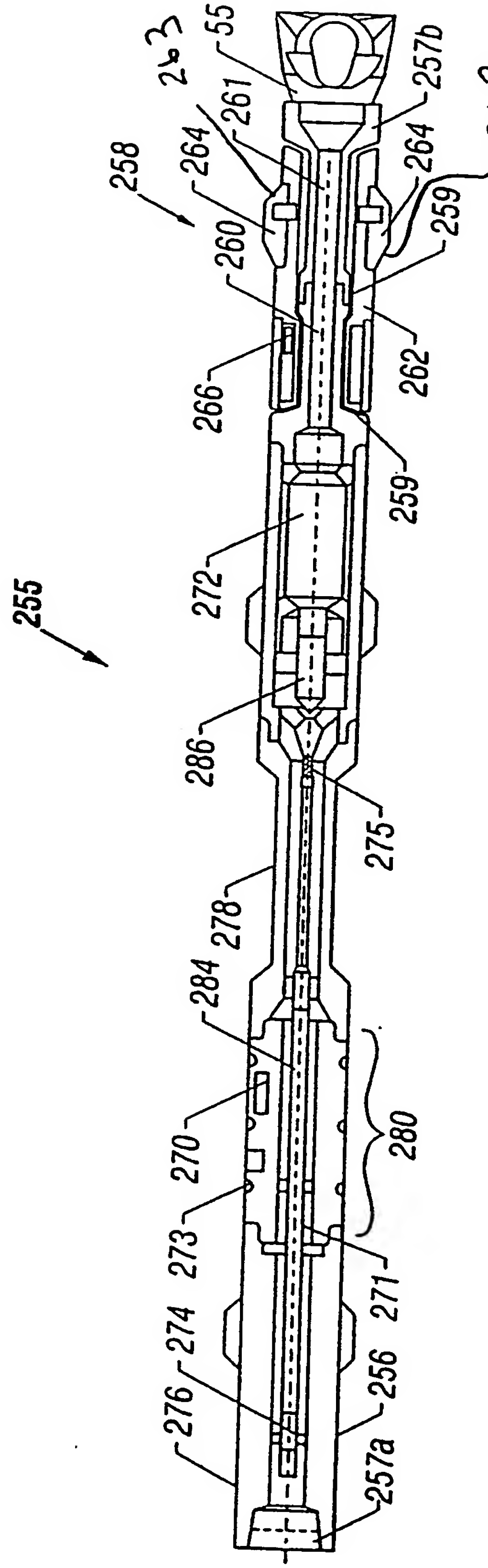
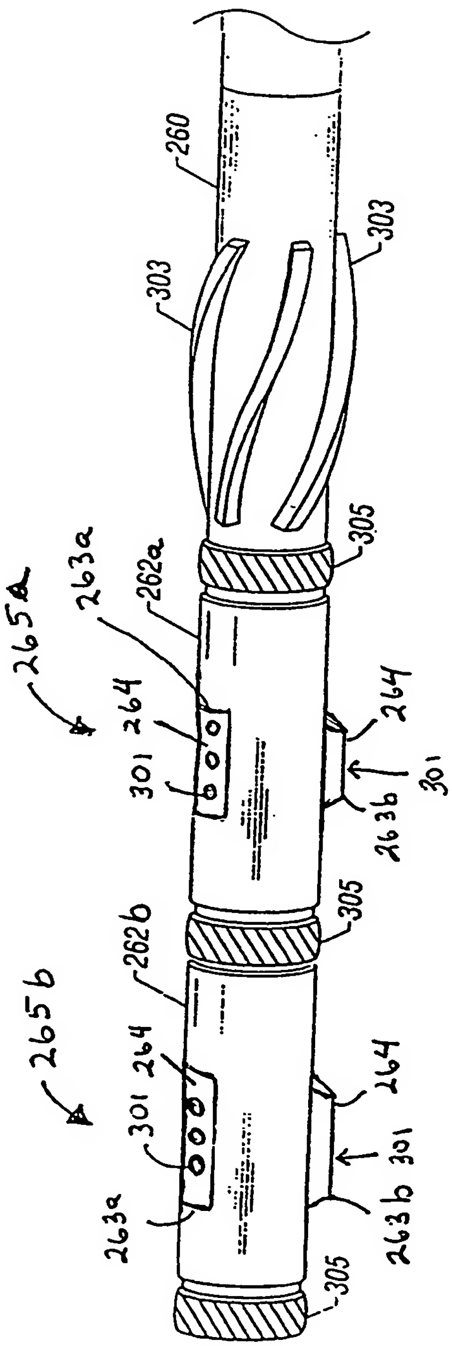

55
263
257b
263
261
264
264
258
259
260
262
266
259
272
255
286
275
278
284
280
270
273
271
274
256
276
257a

FIG. 2


260
303
303
305
262a
263a
265a
264
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264
263b
301
305
262b
265b
301
264
264
263a
301
263b
305

FIG 3A

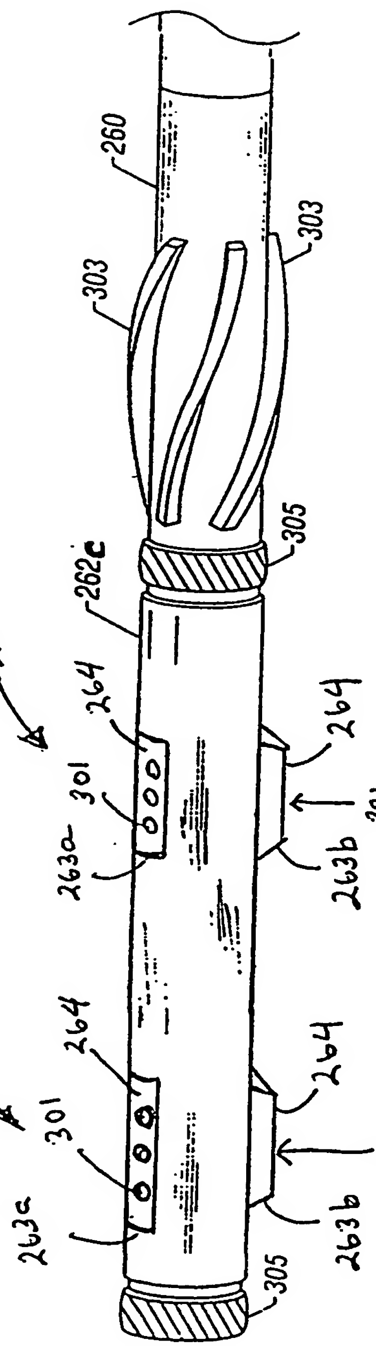
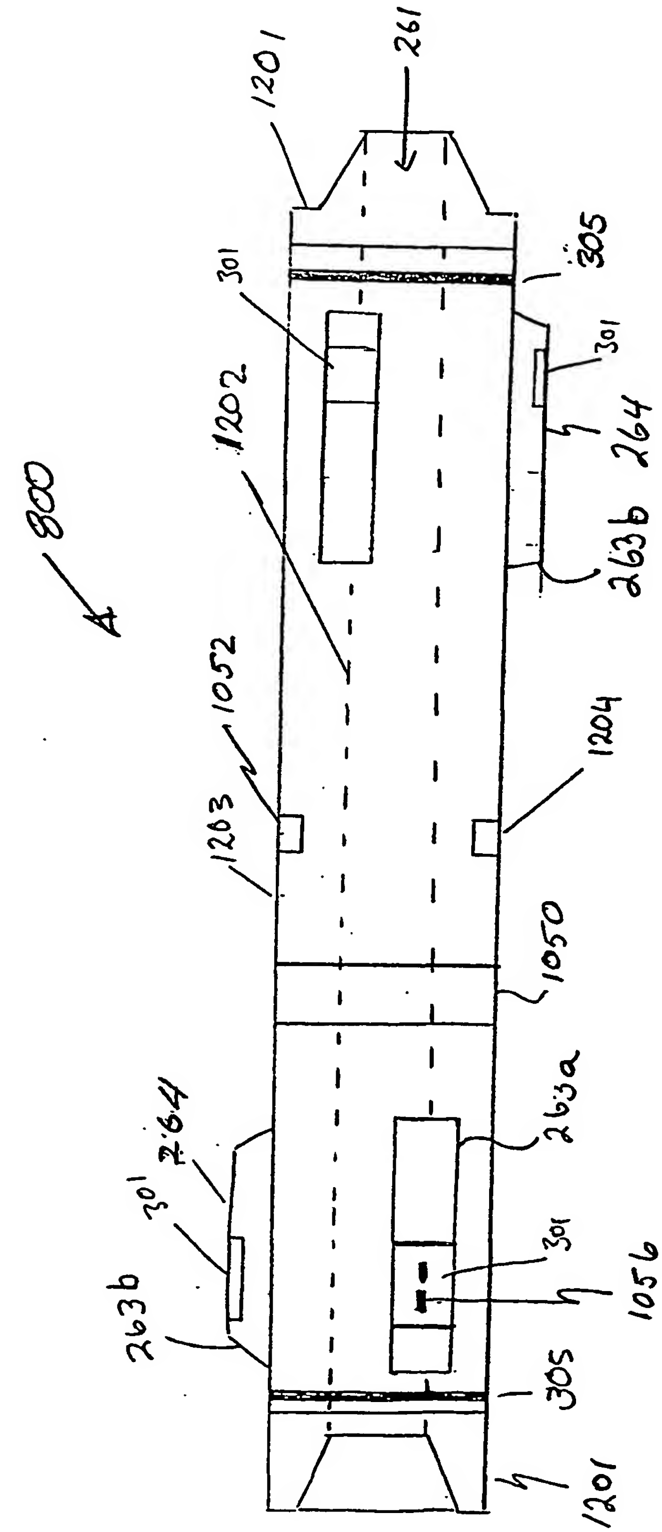

260
303
303
305
262e
265a
264
301
263a
264
301
263b
265b
264
301
263a
264
301
263b
305

FIG 3B


800
1201
261
305
301
1202
301
264
263b
1052
1203
1204
1050
264
301
263b
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301
1056
305
1201

Fig 3C

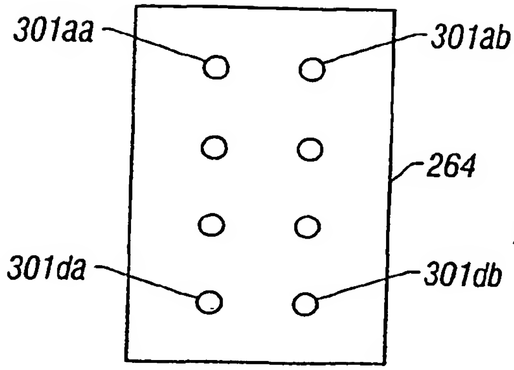

FIG. 3D

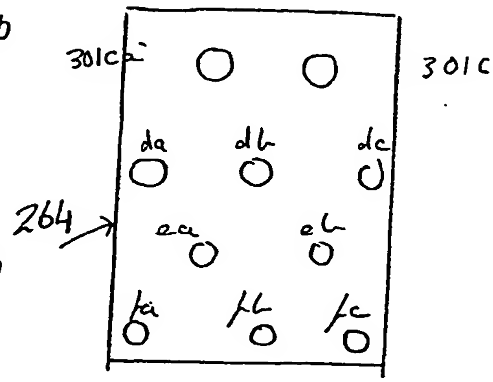

FIG. 3E

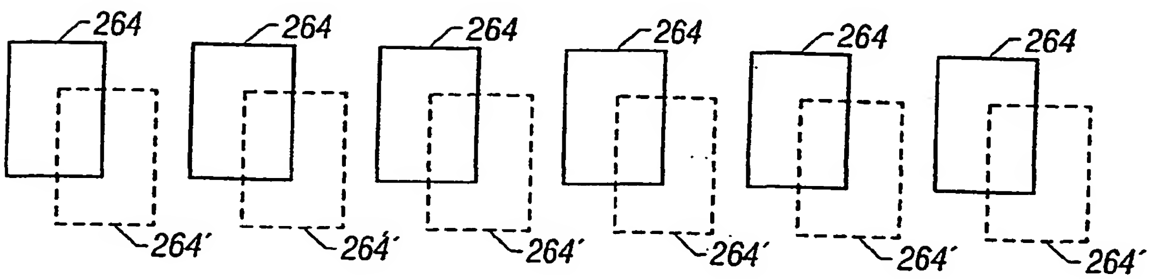

FIG. 3F

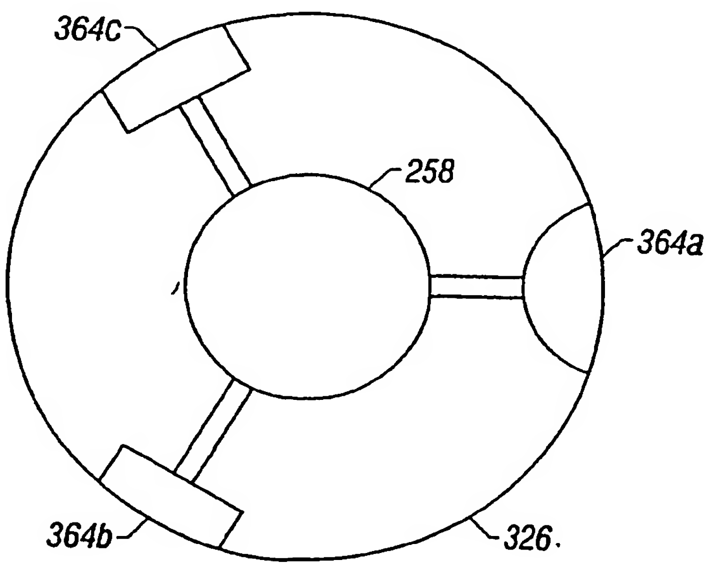

FIG. 3G

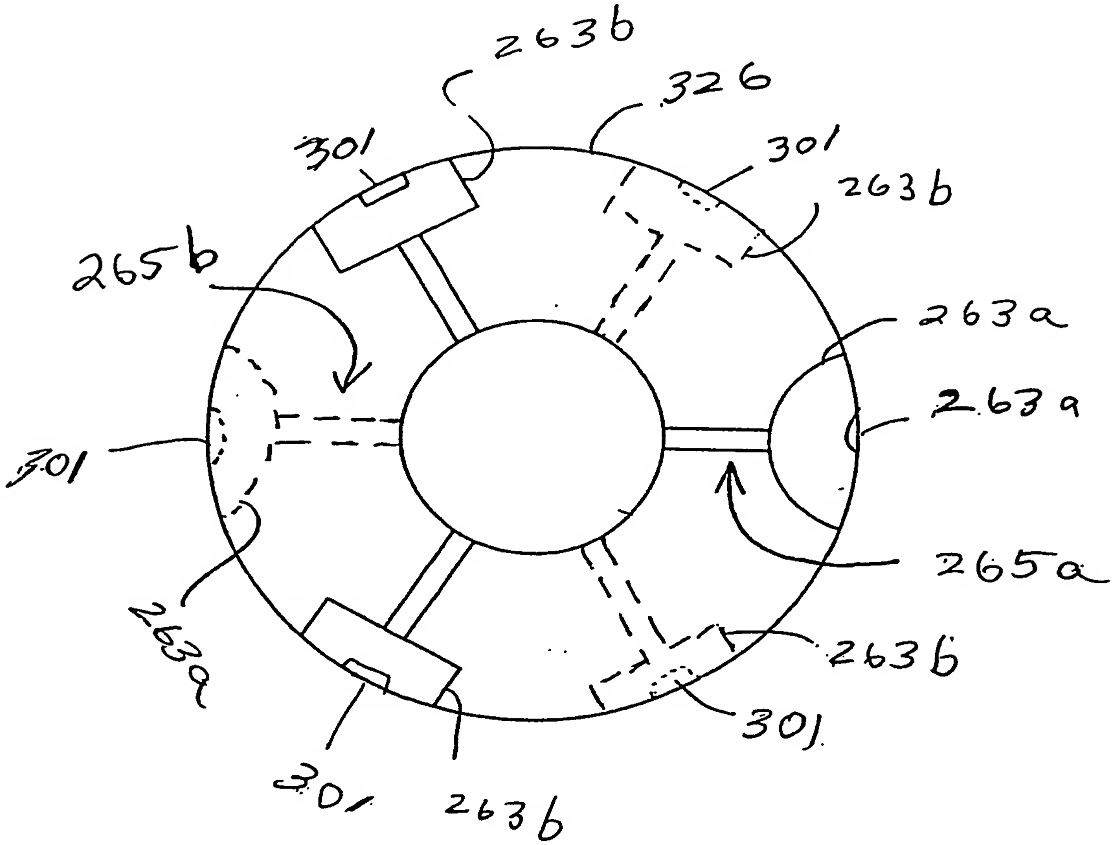
263b
326
301
301
263b
265b
263a
263a
301
265a
263a
263b
301
301
263b

FIG 3H

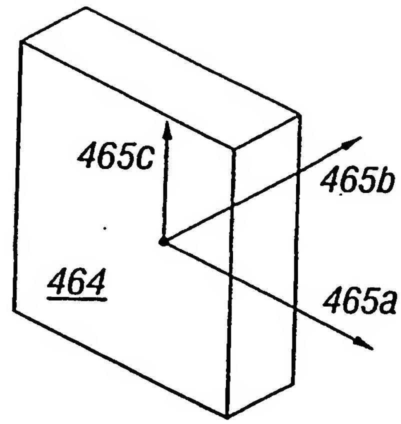
465c
465b
464
465a

FIG. 3I

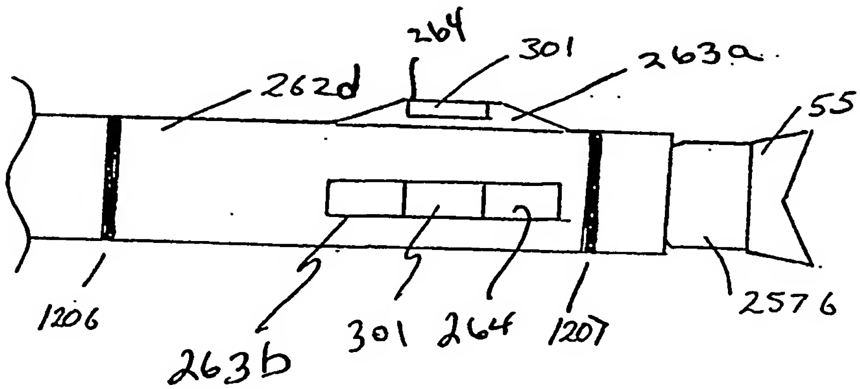
264
301
263a
262d
55
1206
263b
301
264
1207
257b

FIG. 3J

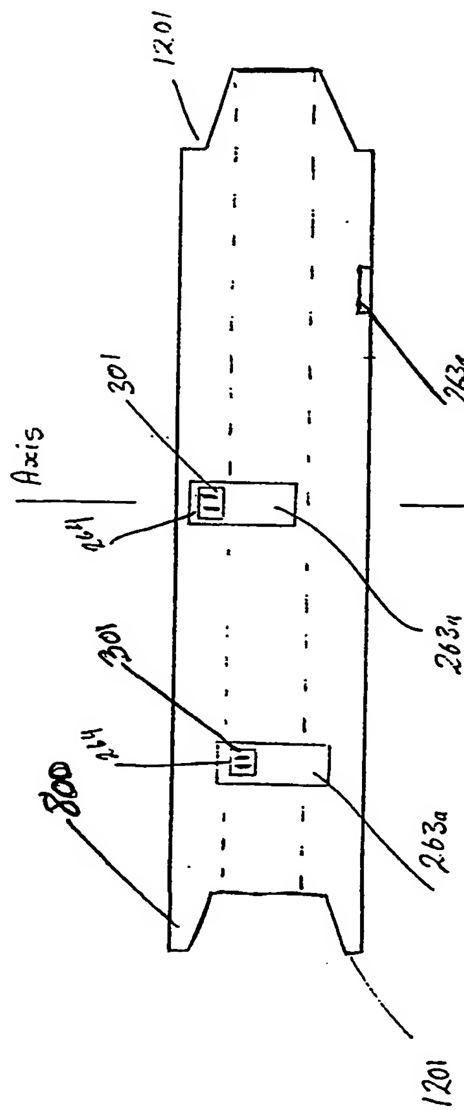

Fig 3K

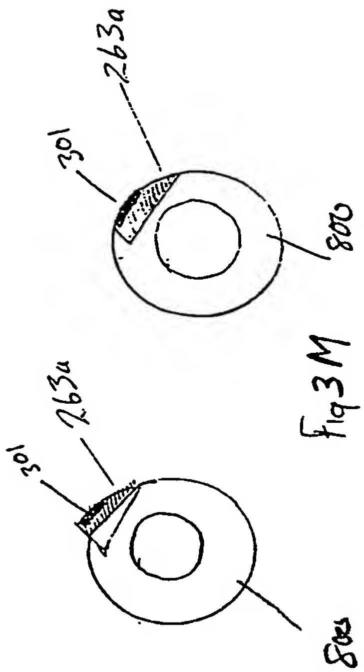

Fig 3M

Fig 3L

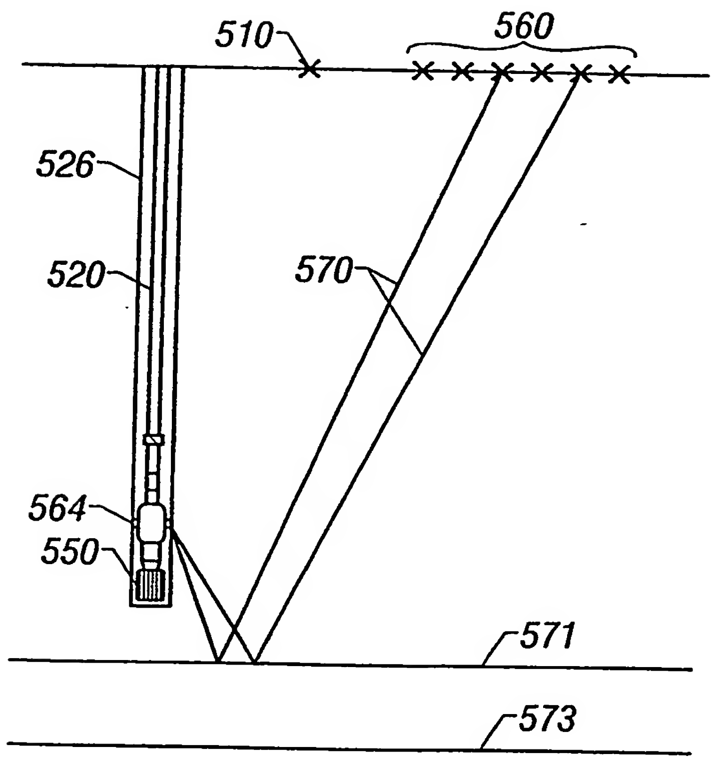

FIG. 4

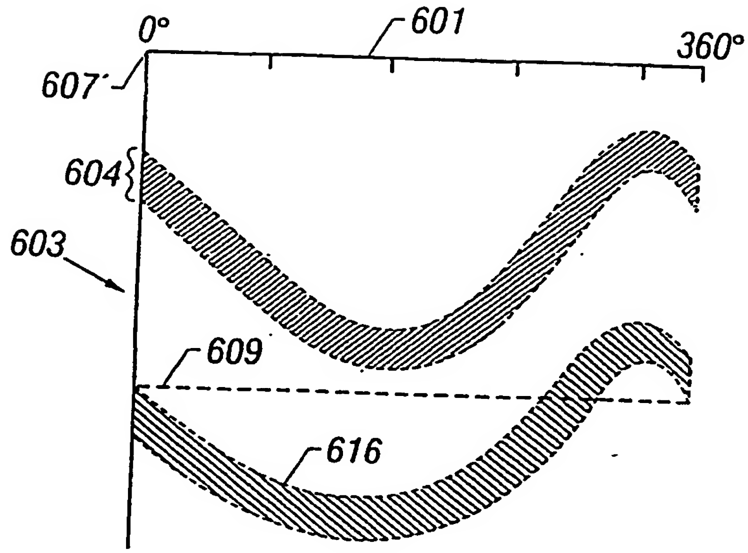

FIG. 5A

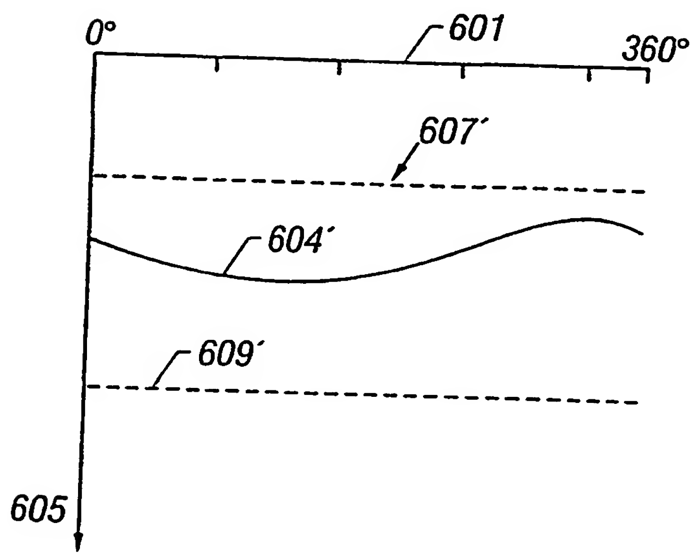

FIG. 5B

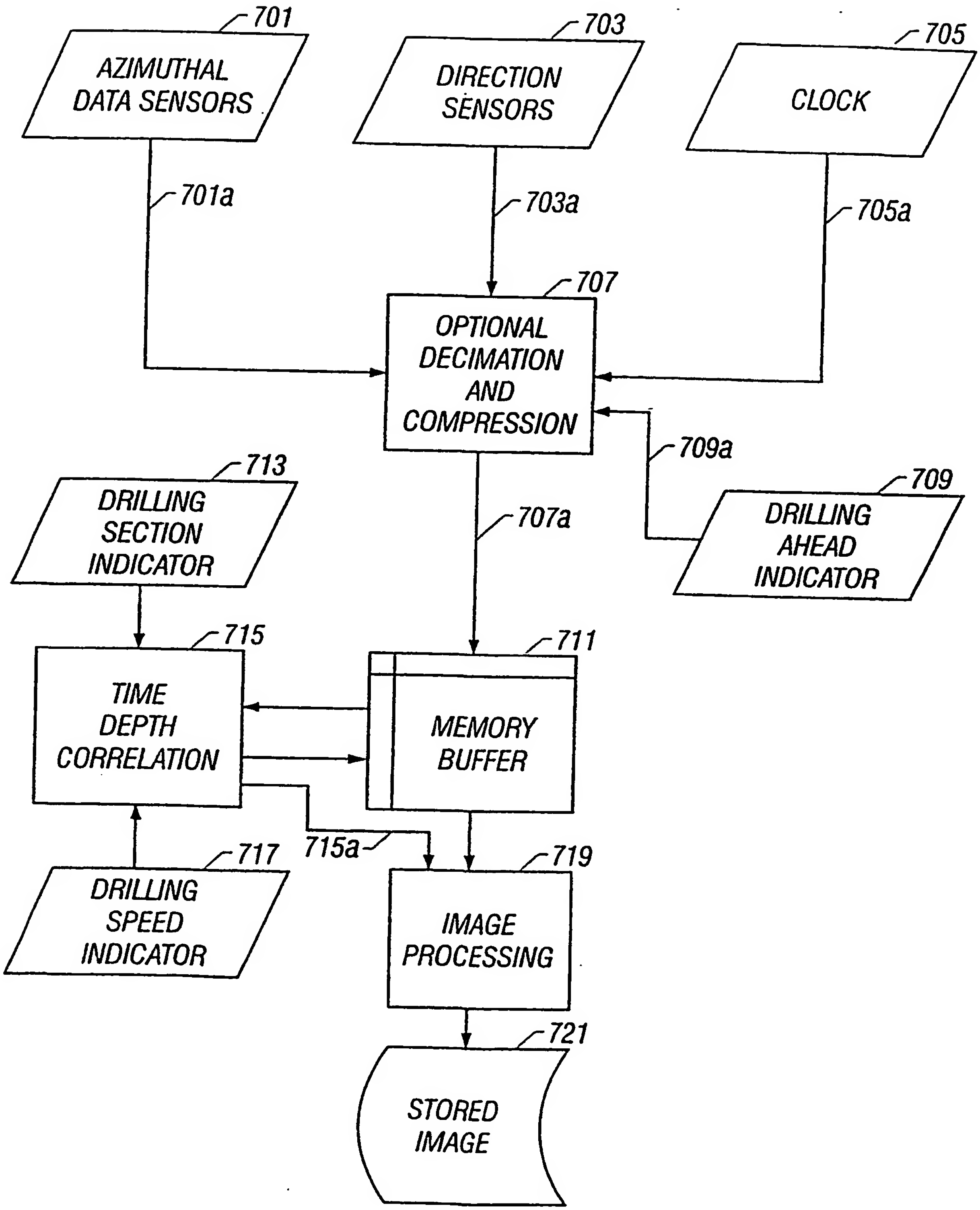
701
AZIMUTHAL DATA SENSORS
703
DIRECTION SENSORS
705
CLOCK
701a
703a
705a
707
OPTIONAL DECIMATION AND COMPRESSION
709a
713
DRILLING SECTION INDICATOR
709
DRILLING AHEAD INDICATOR
707a
715
TIME DEPTH CORRELATION
711
MEMORY BUFFER
717
715a
719
DRILLING SPEED INDICATOR
IMAGE PROCESSING
721
STORED IMAGE

FIG. 6A

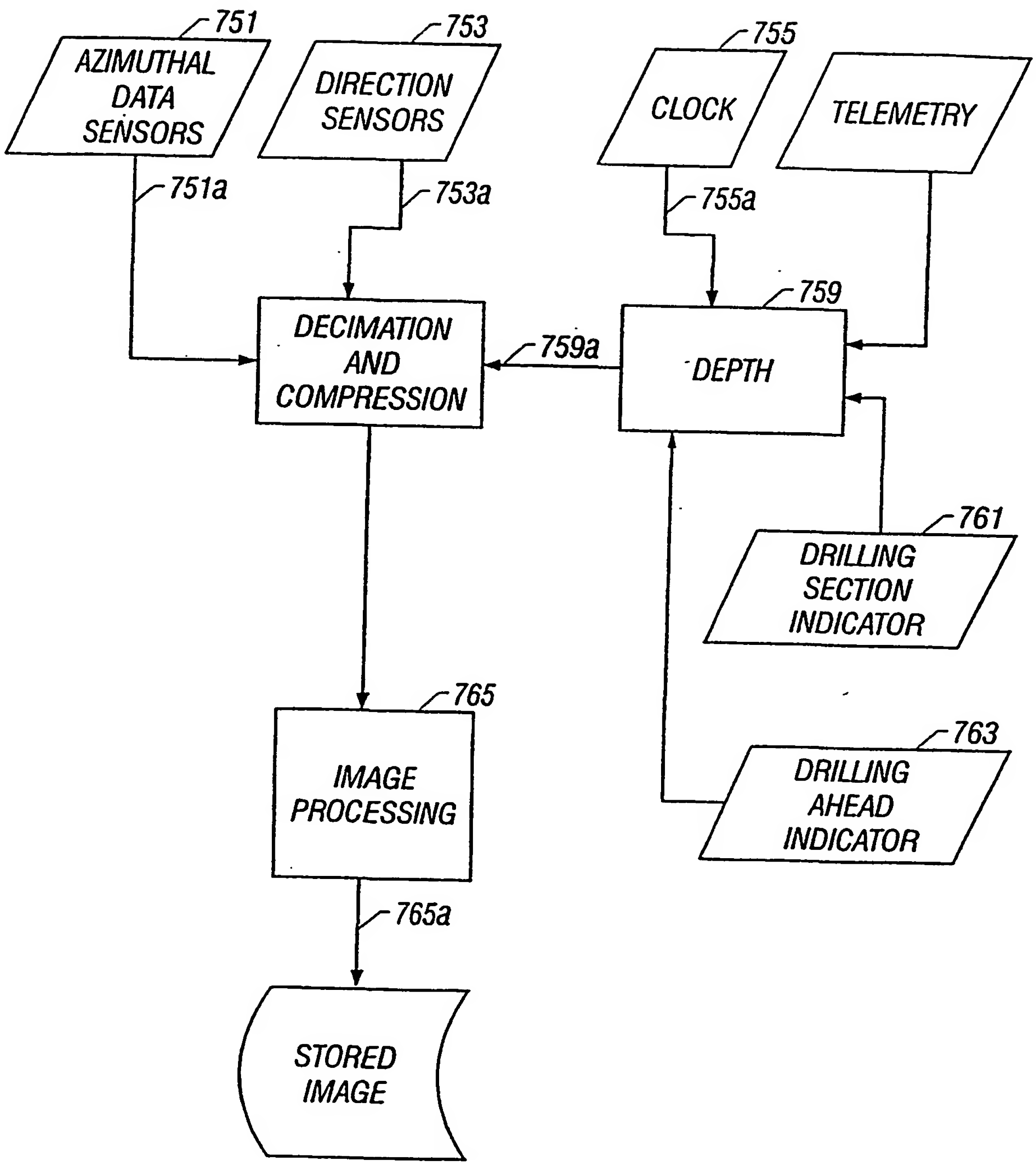
751
AZIMUTHAL DATA SENSORS
753
DIRECTION SENSORS
755
CLOCK
TELEMETRY
751a
753a
755a
759
DECIMATION AND COMPRESSION
759a
DEPTH
761
DRILLING SECTION INDICATOR
765
IMAGE PROCESSING
763
DRILLING AHEAD INDICATOR
765a
STORED IMAGE

FIG. 6B

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(71) Applicant: BAKER HUGHES INCORPORATED [US/US]; Suite 1200, 3900 Essex, Houston, TX 77027 (US).

(72) Inventors: FREDERICKS, Paul; 4307 Garden Hills Lane, Kingwood, TX 77345 (US). MACCALLUM, Donald; 78 North Old cedar circle, The woodlands, TX 77382 (US).

(74) Agents: RIDDLE, J., Albert et al.; Baker Hughes Incorporated, 1999 Rankin Road, Houston, TX 77073 (US).

(81) Designated States *(national)*: AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, CA, CH, CN, CU, CZ, DE, DK, EE, ES, FI, GB, GE, GH, GM, HU, ID, IL, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, UA, UG, UZ, VN, YU, ZW.

(84) Designated States *(regional)*: ARIPO patent (GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE, TR), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

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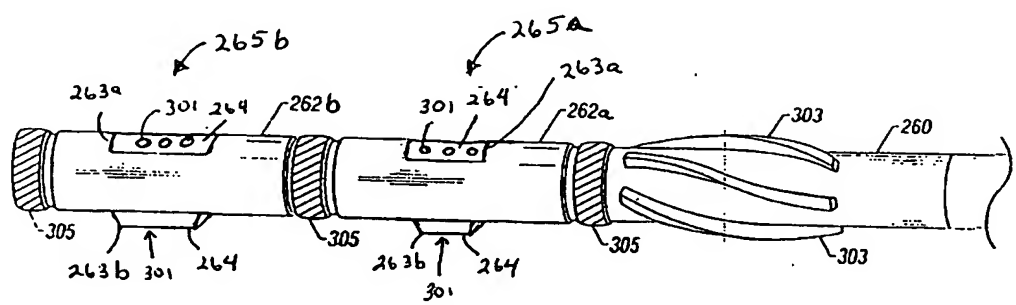
(54) Title: RIB-MOUNTED LOGGING-WHILE-DRILLING (LWD) SENSORS



(57) Abstract: A logging-while-Drilling method and apparatus for obtaining information about a formation uses a plurality of rib sets with pad-mounted sensor on one or more selectively non-rotating sleeves attached to a rotating housing that is part of a drilling assembly. The sensors may be density, neutron, NMR, resistivity, sonic, dielectric or any number of other sensors. In an alternative arrangement, the sensors rotate with the drill string.

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INTERNATIONAL SEARCH REPORT

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According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 G01V E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, WPI Data, PAJ

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 99 45234 A (BAKER HUGHES INC) 10 September 1999 (1999-09-10) page 25, line 16 -page 27, line 22	1-12
A	GB 2 334 982 A (BAKER HUGHES INC) 8 September 1999 (1999-09-08)	1-12
X	page 10, line 5 -page 11, line 3 page 13, line 18 - line 21 page 26, line 21 - line 22 claims 1-6,14-21,24-29	13-26
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-/--

[X] Further documents are listed in the continuation of box C.

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Date of the actual completion of the international search	Date of mailing of the international search report
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Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL – 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Häusser, T

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C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
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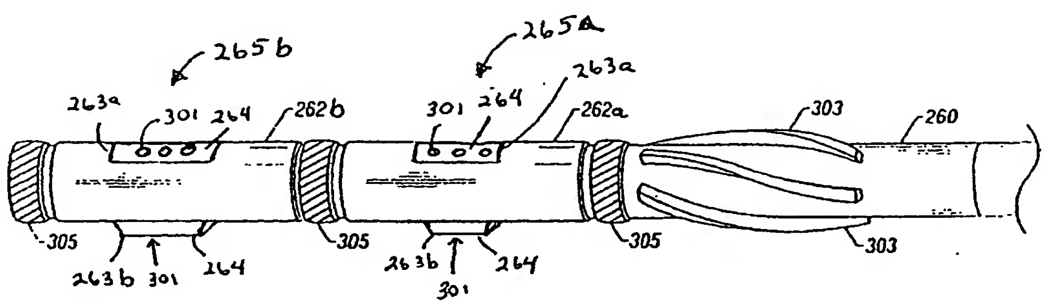

(57) Abstract: A logging-while-Drilling method and apparatus for obtaining information about a formation uses a plurality of rib sets with pad-mounted sensor on one or more selectively non-rotating sleeves attached to a rotating housing that is part of a drilling assembly. The sensors may be density, neutron, NMR, resistivity, sonic, dielectric or any number of other sensors. In an alternative arrangement, the sensors rotate with the drill string.

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Rib-Mounted Logging-While-Drilling (LWD) Sensors

FIELD OF THE INVENTION

This invention relates to the acquisition and processing of data acquired by a logging-while-drilling (LWD) tool during the drilling of a well borehole. More particularly, the invention relates to methods and devices for acquiring data downhole using sensors in contact with the borehole wall, processing the data and transmitting to the surface, in real-time, parameters of the formation penetrated by the borehole as the borehole is being drilled using LWD telemetry.

BACKGROUND OF THE INVENTION

Modern well drilling techniques, particularly those concerned with the drilling of oil and gas wells, involve the use of several different measurement and telemetry systems to provide petrophysical data and data regarding drilling mechanics during the drilling process. Data are acquired by sensors located in the drill string near the bit and either stored in downhole memory or transmitted to the surface using LWD telemetry devices.

A downhole device incorporating resistivity, gravity and magnetic measurements on a rotating drillstring is known in the art. A downhole processor uses the gravity and magnetic data to determine the orientation of the drill string, and using measurements from the resistivity device, makes measurements of formation resistivity at time intervals selected to

give measurements spaced around the borehole. These data are compressed and transmitted uphole by a mud pulse telemetry system. The depth of the resistivity sensor is computed at the surface and the data are decompressed to give a resistivity image of the face of the borehole wall with an azimuthal resolution of 30° or better.

Methods using the known apparatus described above methods are limited to making resistivity measurements in the subsurface and fail to address the issue of other useful measurements that could be made using a logging-while drilling (LWD) device. LWD is similar to methods known as measurement-while-drilling (MWD), and any reference herein to LWD is intended to include MWD, as an alternative embodiment.

The devices described above are also limited to measurement devices that rotate with the drill string and do not take advantage of current drilling methods wherein a mud motor is used and the drill bit could be rotating at a different speed from the drill string or wherein a non-rotating sleeve may be available on which substantially non-rotating measuring devices could be located. The present invention overcomes these inadequacies.

SUMMARY OF THE INVENTION

The present invention is an apparatus and method of making measurements of a plurality of parameters of interest of the formation

surrounding a borehole while a drillstring with a bit at an end thereof is drilling the borehole. In one aspect of the invention, a plurality of selectively non-rotating sleeves are mounted on the drillstring. One or more extendable ribs are mounted on each of the sleeves. Pads are coupled to each rib and sensors are coupled to each pad. When the ribs are extended, measurements of the parameters are made as the drillstring advances through the formation.

In another aspect of the invention, each of a plurality of non-rotating sleeves includes one or more non-extendable (fixed) ribs with pad-mounted sensors coupled thereto. The sensors on the fixed ribs include at least one of a neutron sensor and a density sensor. Other additional sensors may also be used.

In another aspect of the invention an extendable rib and a plurality of fixed ribs are disposed about the outside of a non-rotating sleeve to define a rib set. Each rib of the rib set includes a pad and a plurality of sensors coupled thereto. A plurality of rib sets are mounted on a single non-rotating sleeve, or one rib set may be mounted on each of a plurality of non-rotating sleeves.

In another aspect of this invention, an extendable rib or plurality of extendable ribs are disposed the outside of a subassembly (or sub) that is part of the drill string. As the drillstring rotates the ribs rotate. Each rib

contains a pad and a plurality of sensors. The subassembly is provided with sensors that enable the relative position of each rib to be determined with reference to a direction or gravitational orientation.

In another aspect of the invention, the drill bit is mounted on a rotating drillstring and the downhole assembly is provided with sensors that rotate with the drillstring to make measurements of the parameters of interest. The assembly is provided with magnetic, gravitational and/or inertial sensors to provide information on the orientation of the measurement sensors. A telemetry system sends information downhole about the depth of the drilling assembly. A processor downhole combines the depth and azimuth information with the measurements made by the rotating sensors, uses redundancy in the data to improve S/N ratio, compresses the data and sends it uphole by a telemetry system or stores it downhole for later retrieval.

In another aspect of the invention, the drill bit is driven by a downhole drilling motor. The motor may be on a rotating drillstring or on coiled tubing. The sensors for measuring the parameters of interest could be rotating with the drill bit. Alternatively, the sensors could have one of several configurations. In one configuration, the sensors are mounted on a substantially non-rotating sleeve; in another configuration, the sensors are mounted on pads and the pads are coupled to ribs that could be rotating or non-rotating, the pads being hydraulically or mechanically

actuated to make contact with the borehole wall. In any of these arrangements, the downhole assembly is provided with sensors that make measurements of the parameters of interest. The assembly is provided with magnetic, gravitational and/or inertial sensors to provide information on the orientation of the measurement sensors. A telemetry system sends information downhole about the depth of the drilling assembly. A microprocessor downhole combines the depth and azimuth information with the measurements made by the rotating sensors, uses redundancy in the data to improve S/N ratio, compresses the data and sends it uphole by a telemetry system. The parameters of interest include resistivity, density, compressional and shear wave velocity and structure, dipmeter, dielectric constant, acoustic porosity, NMR properties and seismic images of the formation.

In another aspect of the invention, the drill bit is adapted to function as a resistivity sensor. A current is generated by a first toroid. The current flows through the tool assembly, drill bit and formation. Current in a second toroid is generated by the current flowing through the tool and a resistivity is determined from current in the second toroid.

As a backup to, or independently of, obtaining the depth information by downhole telemetry, the present invention also provides a capability in the downhole microprocessor to use measurements from sensors at more than one depth to provide a rate of penetration. Surface-

measured depths can also be integrated with the measurements from the sensors using a surface mounted depth tracking system on a drilling rig.

BRIEF DESCRIPTION OF THE FIGURES

FIG. 1 is a schematic illustration of a drilling system.

FIG. 2 illustrates a drilling assembly for use with a surface rotary system for drilling boreholes wherein the drilling assembly has a non-rotating sleeve for effecting directional changes downhole.

FIG. 3A illustrates an arrangement wherein each of two independent non-rotating sleeves includes a rib set comprising an extendable rib and one or more fixed ribs.

FIG. 3B illustrates an arrangement wherein a single non-rotating sleeve includes two rib sets, each rib set comprising an extendable rib and one or more fixed ribs.

FIG. 3C illustrates an alternative embodiment of the single non-rotating sleeve arrangement of **FIG. 3B**.

FIG. 3D-3E illustrate alternative arrangements of resistivity sensors on a pad.

FIG. 3F illustrates the overlap between pads on a rotating sensor arrangement.

FIG. 3G illustrates an arrangement of density sensors according to the present invention.

FIG. 3H illustrates an arrangement of offset density and neutron sensors according to the present invention.

FIG. 3I illustrates the arrangement of elastic transducers on a pad.

FIG. 3J shows an embodiment of the present invention wherein the drill bit is used as an electrode for resistivity measurements.

FIG. 3K shows an alternative embodiment of the present invention.

FIGS. 3L-3M are cross section views of the tool of **FIG. 3K**.

FIG. 4 illustrates the acquisition of a set of reverse VSP data according to the present invention.

FIGS. 5A- 5B show a method by which depth is calculated downhole..

FIG. 6A and **6B** are schematic illustrations of the sequence of data flow in processing the data.

DETAILED DESCRIPTION OF THE INVENTION

FIG. 1 shows a schematic diagram of a drilling system **10** having a drilling assembly **90** shown conveyed in a borehole **26** for drilling the wellbore. The drilling system **10** includes a conventional derrick **11** erected on a floor **12** which supports a rotary table **14** that is rotated by a prime mover such as an electric motor (not shown) at a desired rotational speed. The drill string **20** includes a drill pipe **22** extending downward from the rotary table **14** into the borehole **26.** The drill bit **50** attached to the end of the drill string breaks up the geological formations when it is rotated to drill the borehole **26.** The drill string **20** is coupled to a drawworks **30** via a Kelly joint **21**, swivel, **28** and line **29** through a pulley **23.** During drilling operations, the drawworks **30** is operated to control the weight on bit, which is an important parameter that affects the rate of

penetration. The operation of the drawworks **30** is well known in the art and is thus not described in detail herein. A depth tracking system **S4** is well known in the art and is shown coupled to the drawworks **30**.

During drilling operations, a suitable drilling fluid **31** from a mud pit (source) **32** is circulated under pressure through the drill string by a mud pump **34.** The drilling fluid passes from the mud pump **34** into the drill string **20** via a desurger **36**, fluid line **38** and Kelly joint **21.** The drilling fluid **31** is discharged at the borehole bottom **51** through an opening in the drill bit **50.** The drilling fluid **31** circulates uphole through the annular space **27** between the drill string **20** and the borehole **26** and returns to the mud pit **32** via a return line **35.** A sensor S_1 preferably placed in the line **38** provides information about the fluid flow rate. A surface torque sensor S_2 and a sensor S_3 associated with the drill string **20** respectively provide information about the torque and rotational speed of the drill string. Additionally, a sensor (not shown) associated with line **29** is used to provide the hook load of the drill string **20.**

In one embodiment of the invention, the drill bit **50** is rotated by only rotating the drill pipe **52.** In another embodiment of the invention, a downhole motor **55** (mud motor) is disposed in the drilling assembly **90** to rotate the drill bit **50** and the drill pipe **22** is rotated usually to supplement the rotational power, if required, and to effect changes in the drilling direction.

The mud motor **55** is coupled to the drill bit **50** via a drive shaft (not shown) disposed in a bearing assembly **57.** The mud motor rotates the drill bit **50** when the drilling fluid **31** passes through the mud motor **55** under pressure. The bearing assembly **57** supports the radial and axial forces of the drill bit. A stabilizer **58** coupled to the bearing assembly **57** acts as a centralizer for the lowermost portion of the mud motor assembly.

In one embodiment of the invention, a drilling sensor module **59** is placed near the drill bit **50.** The drilling sensor module contains sensors, circuitry and processing software and algorithms relating to the dynamic drilling parameters. Such parameters preferably include bit bounce, stick-slip of the drilling assembly, backward rotation, torque, shocks, borehole and annulus pressure, acceleration measurements and other measurements of the drill bit condition. The drilling sensor module processes the sensor information and transmits it to the surface control unit **40** via a suitable telemetry system **72.**

FIG. 2 shows a schematic diagram of a rotary drilling assembly **255** conveyable downhole by a drill pipe or coiled tube (not shown). The drilling assembly **255** includes a device for changing drilling direction without stopping the drilling operations for use in the drilling system **10** shown in **FIG. 1.** The drilling assembly **255** has an outer housing **256** with an upper joint **257a** for connection to the drill pipe (not shown) and a lower joint **257b** for accommodating the drill bit **55.** During drilling operations,

the housing **256**, and thus the drill bit **55**, rotate when the drill pipe is rotated by the rotary table at the surface. The lower end **258** of the housing **256** has reduced outer dimensions **258** and bore **259** therethrough. The reduced-dimensioned end **258** has a shaft **260** that is connected to the lower end **257b** and a passage **261** for allowing the drilling fluid to pass to the drill bit **55.** A selectable non-rotating sleeve **262** is disposed on the outside of the reduced dimensioned end **258**, in that when the housing **256** is rotated to rotate the drill bit **55**, the non-rotating sleeve **262** remains in its position when selected (engaged) or rotates with the housing **256** when not selected (disengaged). There are several mechanisms known in the art for engaging and disengaging a tool member and thus not shown or described in detail herein. One or more independently adjustable extendable ribs **263a** are disposed on the outside of the non-rotating sleeve **262.** Each extendable rib **263a** is preferably hydraulically operated by a control unit in the drilling assembly **255.** Those versed in the art would also recognize that these ribs, because they are provided with the ability for selectively extending or retracting during drilling operations, can also be used as stabilizers and for controlling the drilling direction. Mechanisms for extending the ribs **263a** could be operated by hydraulic, mechanical or electrical devices. Furthermore, the extendable ribs **263a** may be biased in an extended or in a retracted position. A commonly used mechanical biasing arrangement is to have the extendable ribs mounted on springs that keep the extendable ribs biased in an extended or retracted position. Such

devices would be familiar to those versed in the art.

Also disposed on the sleeve **262** are one or more fixed ribs **263b**. The term "fixed" as used herein with respect to ribs **263b** is defined as being mounted in a substantially immovable relationship in a radial direction with respect to the sleeve **262**. In a preferred embodiment there are two fixed ribs **263b** and one extendable rib **263a** making a rib set **265**. The ribs **263a** and **263b** comprising the rib set **265** are located on the sleeve **262** at substantially the same distance along the longitudinal axis of the sleeve and each rib is spaced substantially equally about the circumference of the sleeve **262** from other ribs in the set **265**. In preferred embodiments to be discussed in detail hereinafter, there are at least two rib sets disposed on the drilling assembly **255**.

Each rib **263a** and **263b** includes a pad **264** for making contact with the borehole wall. A plurality of formation sensors (not shown) is located on each of the pads **264.** Illustrative arrangements of the formation sensors are discussed below in reference to **FIGS. 3D- 3I.**

The drilling assembly **255** also includes a directional sensor **271** near the upper end **257a** and sensors for determining the temperature, pressure, fluid flow rate, weight on bit, rotational speed of the drill bit, radial and axial vibrations, shock and whirl. Without limiting the scope of the invention, the directional sensors **271** could be of the magnetic or

inertial type. The drilling assembly **255** may include a number of non-magnetic stabilizers **276** near the upper end **257a** for providing lateral or radial stability to the drill string during drilling operations in addition to the support provided by the ribs **263a** and **263b**. A flexible joint **278** is disposed between the section **280** and the section containing the non-rotating sleeve **262.** A control unit designated by **284** includes a control circuit or circuits having one or more processors. The processing of signals is performed generally in the manner described below in reference to **FIG. 5A-5B**. A telemetry device, in the form of an electromagnetic device, an acoustic devise, a mud-pulse device or any other suitable device, generally designated herein by **286** is disposed in the drilling assembly at a suitable place. A microprocessor **272** is also disposed in the drilling assembly at a suitable location.

Referring now to **FIG. 3A**, the drilling assembly described above and shown in **FIG. 2** preferably includes two rib sets **365a** and **365b**. **FIG. 3A** illustrates an arrangement wherein the two rib sets **265a** and **265b** are coupled to two independent non-rotating sleeves **262a** and **262b**. Shown are the drilling shaft **260** with two non-rotating sleeves **262a** and **262b** mounted on the shaft **260**. A plurality of ribs **263a** and **263b** with sensors **301** are attached to each sleeve **262.** In an exemplary embodiment, each rib set **265a** and **265b** comprises a selectively extendable rib **263a** and one or more fixed ribs **263b**. Each rib **263a** and **263b** has a pad **264** coupled thereto. Each pad **264** has a sensor **301** for measuring a

parameter of interest. The combination of a pad **264** and sensor **301** is also called a pad-mounted sensor. The mechanism for moving the extendable rib **263a** out toward the borehole, whether it be hydraulic, a spring mechanism or another mechanism is not shown. In this arrangement, the two non-rotating sleeves **262a** and **262b** are independently controllable in that each sleeve can be engaged or disengaged without affecting the operation of the other sleeve. Likewise, the selectively extendable rib **263a** on one sleeve **262a** can be extended or retracted without affecting (or being affected by) the position of the selectively extendable rib 263a coupled to the second sleeve **262b**.

In one embodiment, two toroids **305** that are wound with a current carrying conductor (not shown) surround the shaft **260**. The toroids are arranged with same polarity, so that upon passage of a current in the toroid **305**, a circumferential magnetic field is induced in the two toroids **305**. This magnetic field, in turn, induces an electric field along the axis of the shaft **260**. The leakage current measured by at least one of the sensors **301** is then a measure of the resistivity of the formation adjacent to the sensors, with the leakage current being substantially radial. Such an arrangement has been used before in wireline logging but has not been attempted before in measurement while drilling applications. The shaft **260** is provided with stabilizer ribs **303** for controlling the direction of drilling.

In a preferred embodiment, the sensors **301** on the extendable rib **263a** of the first rib set **265a** are resistivity sensor (buttons) while the sensor on at least one of the fixed ribs **263b** of the first rib set **265a** is a density sensor. The sensors **301** of the second rib set **265b** include a neutron sensor on at least one fixed rib **263b** and resistivity sensors on the extendable rib **263a**.

In an alternative embodiment, all rib-mounted sensors are of the same type. The specific application controls the selection of sensor type. For example, one application may require resistivity sensors while another application requires another sensor technology.

Figure 3B illustrates an alternative embodiment wherein rib-mounted sensors are coupled to a single non-rotating sleeve **262c**. This single-sleeve arrangement provides fixed positioning of the ribs **263a** and **263b** of the first rib set **265a** relative to the ribs **263a** and **263b** of second rib set **265b**. This arrangement provides a simpler design and reduces the need to calculate or measure the position of the sensors **301** relative to each other. The embodiment shown includes a rotatable shaft **260** having a single long non-rotating sleeve **262c** coupled to the shaft **260** at a reduced dimensioned section similar to the embodiment described above and shown in **FIG. 2**. A first rib set **265a** comprising a selectively extendable rib **263a** is coupled to the sleeve **262c**. A pad **264** suitable for maintaining sliding contact with a borehole is coupled to the extendable

rib **263a**. One or more sensors **301** are operatively associated with the pad **264**. The first rib set **265a** further includes one or more fixed ribs **263b** coupled to the sleeve **262c**. The fixed ribs **263b** include pads **264** substantially identical to the pad of the extendable rib. Sensors **301** are coupled to the pads 264 of the fixed ribs **263b**. These fixed-rib sensors may be the same or different as the sensors on the pads of the extendable rib **263a**.

A second rib set **265b** is coupled to the single non-rotating sleeve **262c** longitudinally spaced apart from the first rib set **265a**. The second rib set **265b** includes a selectively extendable rib **263a** coupled to the sleeve **262c**. A pad **264** suitable for maintaining sliding contact with a borehole is coupled to the extendable rib **263a**. One or more sensors **301** are operatively associated with the pad **264**. The second rib set **265b** further includes one or more fixed ribs **263b** coupled to the sleeve **262c**. The fixed ribs **263b** include pads **264** substantially identical to the pad of the extendable rib. Sensors **301** are coupled to the pads **264** of the fixed ribs **263b**. These fixed-rib sensors may be the same or different as the sensors on the pads of the extendable rib **263a**.

In a preferred embodiment, the sensors **301** on the extendable rib **263a** of the first rib set **265a** are resistivity sensor (buttons) while the sensor on at least one of the fixed ribs **263b** of the first rib set **265a** is a density sensor. The sensors **301** of the second rib set **265b** include a

neutron sensor on at least one fixed rib **263b** and resistivity sensors on the extendable rib **263a**.

When extended, the extendable ribs **263a** in the embodiments described above and shown in **FIGS. 3A** and **3B** may function as steering members or stabilizers, although stabilizers **303** may be coupled to the shaft **260** to aid in stabilizing the shaft during drilling operations. In the illustrative embodiment of **FIG. 3B**, one or more current carrying toroids **305** are operatively coupled to the shaft **260** at the reduced dimensioned section to produce an electric field that operates in the same manner as in the discussion above with respect to **Fig. 3A**.

FIG. 3C illustrates and alternative embodiment of the single non-rotating sleeve arrangement of **FIG. 3B**. Shown is a subassembly or ("sub") **800** suitable for operation with a rotary drilling assembly such as described above and shown in **FIG. 2**. The sub **800** is conveyable downhole by drill pipe (not shown). A typical drillpipe compatible connection **1201** is coupled to each end of the sub **800**. Each connector is adapted for the transfer of power and data between the sub **800** and components located elsewhere along the drilling assembly. An external power source (not shown) is preferably used with this arrangement to provide power to the sub **800**. This source can be either the rotary drilling assembly or a separate LWD assembly.

The sub **800** includes a reduced dimension shaft **1202**, between the connections **1201**. A passage **261** allows drilling fluid to flow internally through the sub **800** from a drillpipe connected at the connection **1201**. A selectively non-rotating sleeve **1203** is coupled to the shaft **1202**. The sleeve **1203** is substantially identical to the non-rotating sleeve described above and shown in **FIG 3B**. A plurality of rib sets **265a** and **265b** are mounted on the sleeve **1203**. The rib sets **265a** and **265b** are substantially identical to the rib sets described above and shown in **FIGS. 3A and 3B**. Each rib set comprises an extendable rib **263a** having a pad **264** and a plurality of sensors **301** mounted thereon. Each rib set **265a** and **265b** also includes one or more fixed ribs **263b**, wherein each fixed rib **263b** includes a pad **264** and sensors **301**. Two toroids **305** are disposed on the sleeve **1203** at suitable locations near the joints **1201**. Each toroid is wound with a current carrying conductor (not shown) such that current flowing in a toroid is measured by one or more of the sensors **301**.

The pads **264** can contain a plurality of formation evaluation sensors mounted on each pad in addition or separate to the sensors that could measure the current field generated by the toroids. The pads **264** coupled to the extendable ribs **263a** can be extended to contact the borehole wall by various hydraulic or mechanical devices either automatically or on command from an external source, or the extendable ribs **263a** may be retracted so that the pads **264** do not contact the

borehole wall.

The sub **800** includes communication, data processing and transfer software and electronic hardware not shown in the figure. These components may be located on the sleeve **1203** of at any suitable location on the sub **800**. The software/hardware includes a storage device to store raw, or processed data for later independent access by external computers. The sub **800** further includes software and hardware for performing self diagnostic routes to determine the correct performance of the sub.

The ribs **263a** and **263b** are coupled to the sleeve in a detachable relationship to allow for easy reconfiguration of sensors **301**. The sensors **301** can be removed from the corresponding pad **264** for inspection and repair or replacement with other sensors.

Figure 3C shows a particularly useful configuration wherein two rib sets **265a** and **265b** are separated from each other along a non-rotating sleeve **1203**. The ribs of the first set **265a** are offset with respect to the ribs of the second set **265b** as shown. This configuration enables imaging around-the-borehole. Additional sensors like laterolog type resistivity and circumferentional borehole acoustic imaging mounted to the sleeve **1203** in a suitable location **1204** such as between the two rib sets **265a** and **265b**. Pad orientation is determined using sensors and a processor (not shown) as described above and shown in **FIG. 2** to provide azimuthal and

borehole orientation data.

An alternative arrangement to this configuration is the addition of a mechanism that allows the non rotating sleeve **1203** to rotate with the shaft **1202** at relative speeds ranging from non-rotating to rotating at the same speed as the shaft.

Still referring to **FIG. 3C**, the sub **800** may include electromagnetic induction sensors used to determine the resistivity of the formation. An electromagnetic transmitter antenna **1050** is used to induce an electromagnetic signal into the formation. The antenna **1050** is coupled to the non-rotating sleeve **1203**. One or more sensors **301** are selected from known electromagnetic receiver modules. The electromagnetic sensors **301** are coupled to the extendable rib **263a** of at least one rib set **265b**. Each electromagnetic receiver module **301** has a plurality of slots **1056** behind which receiver coils (not shown) are disposed. The slots are axially spaced apart so that measurements may be made from at least two transmitter to receiver distances. The antenna **1050** is controlled by an electronics module **1052** disposed at a suitable location. Using known electromagnetic induction logging methods, the transmitter sends out a pulse at a frequency and the amplitude and phase of the signal received by the receivers in the receiver modules is used to determine the resistivity of the formation. The frequency of the transmitted signal is typically between 1MHz and 10 MHz.. With the azimuthally disposed

arrangement of the extendable ribs **263a** and the receiver modules **301** on the ribs **263a**, this embodiment makes it possible to determine an azimuthal variation of resistivity. When multiple frequency signals are used, both the resistivity and the dielectric constant of the formation may be determined using known methods. The sensor configuration just described and shown in **FIG. 3C** may also be used with the embodiments described above and shown in **FIG. 3A and 3B**.

In another embodiment of the invention, induction measurements are obtained using an electrode arrangement according to **FIG. 3D**. For example, referring to **Fig 3D,** the electrodes **301aa, 301ab** could be used as a transmitter when pulsed simultaneously, as could the electrodes **301da, 301db**. Similarly, the electrodes **301ba, 301bb** constitute one receiver while the electrodes **301ca, 301cb** constitute a second receiver.

FIGS. 3D and 3E illustrate alternative arrangements for a plurality of resistivity sensors on a single pad **264.** The electrodes are arranged in a plurality of rows and columns. In **FIG. 3D**, two columns and four rows are shown, with the electrodes identified from **301aa** to **301db**. In **FIG. 3E**, four rows of electrodes **301ca - 301fc** are shown. Each row is offset with the rows above and below it by, for example, one half the distance separating the electrodes along a row. In a typical arrangement, the electrodes would be an inch apart. Having a plurality of columns increases the azimuthal resolution of resistivity measurements while

having a plurality of rows increases the vertical resolution of resistivity measurements.

FIG 3F illustrates how a plurality of pads, six in this case, can provide resistivity measurements around the borehole. In the figure, the six pads are shown as **264** at a particular depth of the drilling assembly. For illustrative purposes, the borehole wall has been "unwrapped" with the six pads spread out over 360° of azimuth. As noted above, the pads are on arms that extend outward from the tool body to contact the wall. The gap between the adjacent pads will depend upon the size of the borehole: in a larger borehole, the gap will be larger. As the drilling proceeds, the tool and the pads will move to a different depth and the new position of the pads is indicated by **264.** As can be seen, there is an overlap between the positions of the pads in azimuth and in depth. The tool orientation is determined by the microprocessor **272** from the directional sensors **271.** This overlap provides redundant measurements of the resistivity that are processed as described below with reference to **FIG. 5A** and **5B**.

Those versed in the art would recognize that even with a substantially non-rotating sleeve on the drilling assembly, some rotation of the sleeve will occur. With a typical drilling rate of 60 feet per hour, in one minute, the tool assembly will advance one foot. With a typical rotary speed of 150 rpm, even a sleeve designed to be substantially non rotating

could have a complete revolution in that one minute, providing for a complete overlap. Those versed in the art would also recognize that in an alternate disposition of the sensor that rotates with the drill bit, a complete overlap would occur in less than one second.

FIG. 3G illustrates an arrangement of density sensors according to the present invention. Shown is a cross section of the borehole with the wall designated as **326** and the tool generally as **258.** All pads are shown engaging the wall of the borehole. This arrangement is similar to that used in wireline tools except that in wireline tools, the source is located in the body of the tool.

FIG. 3H illustrates an arrangement of sensors according to the present invention such as described above and shown in **FIG. 3C**. Shown is a cross section of the borehole with the wall designated as **326** and the tool generally as **258.** A first set **265a** of ribs **263a** and **263b** are represented as shown with solid lines, and a second set **265b** of ribs **263a** and **263b** are represented as shown with dashed lines. The first set **265a** being offset with respect to the second set **265b**. The offset of the ribs is preferably selected such that the sensors on the extendable ribs **263a** are positioned toward opposite walls of the borehole **326**. The pads are shown engaging the wall of the borehole.

The arrangements of **FIGS. 3G** and **3H** illustrate a logging-while-

sliding method according to the present invention. These embodiments, as those of **FIGS. 3A-3C** above enable continuous contact with the borehole wall as the drilling assembly traverses the formation. The sensors may be maintaining a substantially straight path along the wall when the non-rotating sleeve is engaged (not rotating with the shaft). The sensors may also be traveling a helical path along the wall when the sleeve is disengaged (rotating with the shaft).

In an alternative arrangement the pads could have elastic (commonly referred to as acoustic) transducers mounted on them. In the simplest arrangement shown in **FIG. 3I**, each pad has a three component transducer (or, equivalently, three single component transducers) mounted thereon. The transducer is adapted to engage the borehole wall and capable of pulsating or vibrating motion in three directions, labeled as **465a, 465b** and **465c**. Those versed in the art would recognize that each of these excitations generates compression and shear waves into the formation. Synchronized motion of transducers on the plurality of pads introduces seismic pulses of different polarization into the formation that can be detected at other locations. In the simplest configuration, the detectors are located on the surface (not shown) and can be used for imaging the subsurface formations of the earth. Depending upon the direction of the pulses on the individual pads, compression and polarized shear waves are preferably radiated in different directions.

FIG. 3J illustrates an alternative embodiment having sensors on extendable ribs **263a** coupled to a non rotating sleeve **262d**. In this configuration the pads **264** are instrumented with resistivity or alternative sensors as described above. The drill bit **55** is adapted to function as an electrode to give a resistivity reading at the bit.

A current is driven by a known voltage through a toroid **1206.** The current flowing in the toroid **1206** induces a voltage along the collar **2576**. The voltage on the collar **2576** sets up current in the formation near the drill bit **55**. The current flows through the formation, drill bit **55** and collar **2576**. A receiver coil **1207**, near the bottom of the tool measures the current flowing in the tool. Knowing the voltage, the bit resistivity is determined by measuring the current using methods described herein.

Referring now to **FIG. 3K**, the extendable ribs that contain the pad based sensors are housed within a drillstring subassembly **800**. A single or multiple number of ribs **263a** are contained within the body of this sub. Each rib contains a pad **264** mounted with a plurality of sensors **301**. The sub **800** is conveyed downhole by drillpipe. At each end of the sub is a drillpipe compatible connection **1201**. Each connection is adapted for the transfer of power and data between the sub and components of the LWD system located elsewhere in the drillstring. A power source external to sub **800** (not shown) is preferably used with this arrangement.

The extendable ribs extend on command from the external LWD assembly or from a microprocessor within the sub (not shown) as a response to the start of rotation or as a response to a command initiated independently of rotation. When rotation stops the ribs will retract back into the sub as a response to the cessation of rotation or as a response to a command initiated independently of rotation.

FIGS. 3L and **3M** show a cross section through sub **800**. **Fig. 3L** shows the extendable rib **263a** with the pad **264** and sensors **301** extended to contact the borehole wall. **FIG. 3M** shows the extendable rib retracted into the housing of the sub.

The orientation of the sensor packages on each extendable rib is referenced to a number of components (not shown) either within the sub or external to the sub in the LWD system that measure orientation and direction of the drilling assembly.

FIG. 4 illustrates the acquisition of a set of reverse VSP data according to the present invention. A plurality of seismic detectors **560** are disposed at the surface **510.** A borehole **526** drilled by a drill bit **550** at the end of a drillstring **520** is shown. The downhole drilling assembly includes seismic sources **564** on pads that engage the walls of the borehole. Seismic waves **570** radiating from the sources **564** are reflected by boundaries such as **571** and **573** and detected at the surface

by the detectors **560.** The detection of these at the surface for different depths of the drilling assembly gives what is called a reverse Vertical Seismic Profile (VSP) and is a powerful method of imaging formations ahead of the drill bit. Processing of the data according to known methods gives a seismic image of the subsurface. While reverse VSPs using the drill bit itself as a seismic source have been used in the past, results are generally not satisfactory due to a lack of knowledge of the characteristics of the seismic signal and due to poor S/N ratio. The present invention, in which the source is well characterized and is in essentially the same position on a non-rotating sleeve has the ability to improve the S/N ratio considerably by repeatedly exciting the sources in essentially the same position. Those versed in the seismic art would be familiar with the pattern of energy radiated into the formation by the different directions of motions of the transducers **465** and their arrangement on a circular array of pads.

Those versed in the art would also recognize that instead of seismic pulses, the seismic transmitters could also generate swept-frequency signals that continuously sweep through a selected range of frequencies. The signals recorded at the transmitters can be correlated with the swept frequency signal using well known techniques to produce a response equivalent to that of an impulsive seismic source. Such an arrangement requires less power for the transmitters and is intended to be within the scope of the invention.

The VSP configuration could be reversed to that of a conventional VSP, so that downhole sensors on a non-rotating sleeve measure seismic signals from a plurality of surface source positions. Such an arrangement would suffer from the disadvantage that a considerably greater amount of data would have to be transmitted uphole by telemetry.

In an alternate arrangement (not shown), two sets of axially spaced-apart pads are provided on the non-rotating sleeve. The second set of pads is not illustrated but it has an arrangement of detectors that measure three components of motion similar to the excitation produced by the sources **465.** Those versed in the art would recognize that this gives the ability to measure compressional and shear velocities of the formation between the source and the receiver. In particular, because of the ability to directly couple a seismic source to the borehole wall, shear waves of different polarization can be generated and detected. Those versed in the art would know that in an anisotropic formation, two different shear waves with different polarization and velocity can be propagated (called the fast and the slow shear wave). Measurement of the fast and slow shear velocities gives information about fracturing of the formation and would be familiar to those versed in methods of processing the data to obtain this fracturing information.

The same arrangement of having seismic transmitters and receivers on non-rotating pads in the drilling assembly makes it possible

to record reflections from surfaces in the vicinity of the borehole. In particular, it enables the device to obtain distances to seismic reflectors in the vicinity of the borehole. This information is useful in looking ahead of the drillbit and in guiding the drillbit where it is desired to follow a particular geologic formation.

Those versed in the art would recognize that by having an arrangement with four electrodes substantially in a linear arrangement on a number of non-rotating pads, the outer electrodes being a transmitter and a receiver respectively, and by measuring the potential difference between the inner electrodes, a resistivity measurement of the formation can be obtained. Such an arrangement is considered to be conventional in wireline logging applications but has hitherto not been used in measurement-while-drilling applications because of the difficulty in aligning the electrodes on a rotating drillstring.

The embodiments of the present invention discussed above include various sensors located on a non-rotating sleeve that is part of a drilling assembly which includes a downhole mud motor. Those versed in the art would recognize that an equivalent arrangement can be implemented wherein instead of a drillstring, coiled tubing is used. This arrangement is intended to be within the scope of the present invention.

In an alternate embodiment of the invention, the formation sensor

assembly could be directly mounted on the rotating drillstring without detracting from its effectiveness. This was discussed above with respect to resistivity sensors in **FIG. 3D**

The method of processing of the acquired data from any one of these arrangements of formation sensors is discussed with reference to **FIGS 5A- 5B**. For illustrative purposes, **FIG. 5A** illustrates the "unwrapped" resistivity data that might be recorded by a first resistivity sensor rotating in a vertical borehole as the well is being drilled. The horizontal axis **601** has values from 0° to 360° corresponding to azimuthal angles from a reference direction determined by the directional sensor **271.** The vertical axis **603** is the time of measurement. As the resistivity sensor rotates in the borehole while it is moved along with the drill bit, it traces out a spiral path. Indicated in **FIG 5A** is a sinusoidal band **604** corresponding to, say, a bed of high resistivity intersecting the borehole at a dipping angle.

In one embodiment of the invention, the downhole processor **272** uses the depth information from downhole telemetry available to the telemetry device **286** and sums all the data within a specified depth and azimuth sampling interval to improve the S/N ratio and to reduce the amount of data to be stored. A typical depth sampling interval would be one inch and a typical azimuthal sampling interval is 15^0 . Another method of reducing the amount of data stored would be to discard redundant samples within the depth and azimuth sampling interval. Those

versed in the art would recognize that a 2-D filtering of the data set by known techniques could be carried out prior to the data reduction. The data after this reduction step is displayed on a depth scale in **FIG 5B** where the vertical axis **605** is now depth and the horizontal axis **601** is still the azimuthal angle with respect to a reference direction. The dipping resistive bed position is indicated by the sinusoid **604'.** Such a depth image can be obtained from a time image if at times such as **607** and **609**, the absolute depth of the resistivity sensor, **607'** and **609'** were known.

As a backup or as a substitute for communicating depth information downhole, the microprocessor uses data from the additional resistivity sensors on the pads to determine a rate of penetration during the drilling. This is illustrated in **FIG 5A** by a second resistivity band **616** corresponding to the same dipping band **604** as measured at a second resistivity sensor directly above the first resistivity sensor. The spacing between the first and second resistivity sensors being known, a rate of penetration is computed by the microprocessor by measuring the time shift between the bands **604** and **616.** The time shift between the bands **604** and **606** could be determined by one of many methods, including cross-correlation techniques. This knowledge of the rate of penetration serves as a check on the depth information communicated downhole and, in the absence of the downhole telemetry data, can be used by itself to calculate the depth of the sensors.

The method of processing discussed above works equally well for resistivity measurements made by sensors on a non-rotating sleeve. As noted above with reference to **FIG. 3B**, there is still a slow rotation of the sensors that provides redundancy that can be utilized by the processor **272** as part of its processing-before-transmission.

FIG. 6A illustrates the flow of data in one embodiment of the invention. The plurality of azimuthal data sensors (**301** in **FIG. 3A**) are depicted at **701.** The output **701a** of the azimuthal data sensors **701** is azimuthal sensor data as a function of time. The direction sensors (**271** in **FIG. 2**) are denoted at **703.** The output **703a** of the direction sensors **703** is the azimuth of the drilling assembly as a function of time. Using timing information **705a** from a clock **705** and the information **709a** from the drilling ahead indicator **709**, the processor first carries out an optional data decimation and compression step at **707.** The drilling ahead indicator uses a plurality of measurements to estimate the rate of advance of the drill bit. A sensor for measuring the weight on the drill bit gives measurements indicative of the rate of penetration: if the weight on the drill bit is zero, then the rate of penetration is also zero. Similarly, if the mud flow indicator indicates no flow of the mud, then too the drill bit is not advancing. Vibration sensors on the drill bit also give signals indicative of the forward movement of the drill bit. A zero value for weight on the drill bit, mud flow or drill bit vibration means that the sensor assembly is at a constant depth.

This step of data decimation and compression may stack data from multiple rotations of the sensor assembly that fall within a predetermined resolution required in the imaging of the data. This information **707a** consisting of data as a function of azimuth and depth is stored in a memory buffer **711.** A memory buffer with 16 MByte size is used, adequate to store the data acquired using one segment of drill pipe. As would be known to those versed in the art, the drill pipe comes in segments of 30 feet, successive segments being added at the wellhead as drilling progresses.

Using estimates of the drilling speed from **717**, and a drilling section completed indicator **713** a depth - time correlation is performed **715.** The drilling section completed indicator includes such information as the number of drill string segments. The drilling rate estimate is obtained, e.g., from the method given in the discussion of **FIGS. 5A** and **5B** above. The time-depth transformation function **715a** obtained by this is used at **719** to process the data as a function of azimuth and time in the memory buffer **711** to give an image that is a function of azimuth and depth. This image is stored downhole at **721** in a memory buffer. With 16 Mbytes of memory, it is possible to store 1700 feet of data downhole with a 1 inch resolution. This data is later retrieved when tripping the well or could be transmitted uphole using the telemetry device **286.** By processing the data downhole in this fashion, the demand on the telemetry device is greatly reduced and it can be used for transmitting other data relating to

the drilling motor and the drill bit uphole.

The arrangement shown in **FIG. 6A** does not use any telemetry data from the surface to compute depth. In an alternate arrangement shown in **FIG. 6B,** a depth calculation is performed downhole at **759** to give an actual position of the sensor assembly using information from a number of sources including telemetry data. One is the timing information **755a** from the clock **755**. A drilling speed sensor gives an indication of the drilling speed. Drilling speed **756a** is obtained from one of two sources **756.** In one embodiment, a downhole inertial sensor (not shown) is initialized each time that drilling is stopped for adding a section of drill pipe. The information from this inertial sensor provides an indication of drilling speed. In addition, or as an alternative, drilling speed transmitted from the surface by the downlink telemetry could be used and received at the downhole telemetry device **286** is used.

An indicator of the drilling section completed **761**, as discussed above with reference to **713** in **FIG. 6A** is used as an additional input for the depth calculations, as is an estimate from the drilling ahead indicator **763**, discussed above with reference to **709** in **FIG. 6A.** This depth calculation **759a** is used in data compression and decimation **757** (as discussed above with reference to **FIG. 6A**) to process data **751a** from the azimuthal measurement sensors **751** and the data **753a** orientation sensors **753.** The image processing at **765** gives the image data as a

function of depth **765a**, this data being stored downhole **767** with the same resolution as at **721** in **FIG. 6A**. The processing scheme of **FIG. 6B** does not require the memory buffer **711** that is present in **FIG. 6A**; however, it does require more depth data to be transmitted downhole, thus tying up the telemetry link to some extent.

As noted above in the discussion of **FIGS. 5A- 5B**, a combination of both methods could also be used, i.e. perform depth calculations from sensor data downhole in addition to using downlinked data.

The discussion above was with respect to resistivity measurements. Any other scalar measurement made by a sensor can be treated in the same fashion to improve the S/N ratio prior to transmitting it uphole by telemetry. Vector data, such as acquired by compressional and shear wave transducers requires somewhat more complicated processing that would be known to those versed in the art.

As mentioned above, the data transmitted from downhole is indicative of resistivities at uniformly sampled depths of layers of the formation. The data is transmitted in real time. The processes and apparatus described above provide a relatively high resolution color image of the formation in real-time. The resolution of this image may be enhanced even further by using various image enhancement algorithms. These image enhancing algorithms would be familiar to those versed in

the art.

The foregoing description has been limited to specific embodiments of this invention. It will be apparent, however, that variations and modifications may be made to the disclosed embodiments, with the attainment of some or all of the advantages of the invention. In particular, the invention may be modified to make density and acoustic measurements. Therefore, it is the object of the appended claims to cover all such variations and modifications as come within the true spirit and scope of the invention.

CLAIMS

What is claimed is:

1. A formation evaluation apparatus mounted on a drilling assembly including a drill bit for drilling a borehole in a formation, the apparatus being useful for determining a parameter of interest of the formation surrounding a borehole having a longitudinal axis created by the drilling assembly, the apparatus comprising:

   (a) a rotatable housing;

   (b) at least one selectable member on the outside of the housing, the member being a rotating member when not selected and a substantially non-rotating when selected; and

   (c) at least one rib set mounted on the selectable member, the rib set comprising at least one selectively extendable rib having a first pad coupled thereto for making contact with the formation when the extendable rib is extended, the contact being substantially continuous as the drilling assembly traverses the formation, at least one fixed rib having a second pad coupled thereto for making contact with the formation, and a first formation evaluation sensor operatively coupled to the first pad for making a first measurement relating to the parameter of interest of the formation.

2. The apparatus of claim **1** further comprising a processor disposed in the housing, the processor using directional information from a directional sensor operably coupled to the housing and the measurement from one of the first and second formation evaluation sensors to determine the parameter of interest.

3. The apparatus of claim **1** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a jointed pipe, and (ii) coiled tubing.

4. The apparatus of claim **1** further comprising an extension device for moving the extendable rib from a retracted position to an extended position wherein the pad makes contact with the formation.

5. The apparatus of claim **4**, wherein the extension device is selected from a group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.

6. The apparatus of claim **1** wherein the at least one rib set is at least two rib sets comprising a first rib set and a second rib set, the first rib set further including a second formation evaluation sensor operatively coupled to the second pad for making a second measurement relating to the parameter of interest of the formation,

and the second rib set having a further including a third formation evaluation sensor operatively coupled to a third pad for making a third measurement relating to the parameter of interest of the formation.

7. The apparatus of claim **6** wherein the first formation evaluation sensor is a resistivity sensor, the second formation evaluation sensor is a neutron sensor and the third formation evaluation sensor is a density sensor.

8 The apparatus of claim **1** further comprising a first toroid and a second toroid, each toroid being coupled to the selectable member, the first toroid for causing a current to flow through the formation and the drill bit, the second toroid being responsive to the current flowing through the drill bit, and a processor for determining the resistivity of the formation, the determination being based on the current in the second toroid.

9 The apparatus of claim **1** wherein the pad is in contact with the formation and the member is not selected for sliding the pad along the formation in a substantially helical path.

10 The apparatus of claim **1** wherein the pad is in contact with the formation while the member is selected for sliding the pad along

the formation in a substantially straight path.

11 The apparatus of claim **1** wherein the at least one selectable member comprises at least two selectable members.

12. The apparatus of claim **2** wherein the parameter of interest is a resistivity image of the borehole.

13. A formation evaluation apparatus mounted on a drilling assembly for determining a parameter of interest of a formation surrounding a borehole, said apparatus comprising:

(a) a rotatable housing;

(b) a directional sensor operably coupled to the housing for making measurements related to the orientation of the housing;

(c) a telemetry device disposed in the housing, said telemetry device adapted to receive depth information from an uphole controller;

(d) at least one selectively rotatable formation evaluation sensor operatively coupled to the housing and on the outside thereof, said at least one formation evaluation sensor capable of contact with the formation to make measurements related to the parameter of interest, said at least one formation evaluation sensor being selectively

rotatable between a substantially non-rotating state and a rotating state; and

(e) a processor for determining the parameter of interest from the measurements made by the directional sensor, the depth information and the measurements made by the at least one formation evaluation sensor.

14. The apparatus of claim **13** wherein the telemetry device is further adapted to transmit the determined parameter of interest to the uphole controller.

15. The apparatus of claim **13** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a drillstring, and (ii) a coiled tubing.

16. The apparatus of claim **13** further comprising a selectable substantially non-rotating sleeve coupled to the housing, and wherein the at least one formation evaluation sensor is carried by the sleeve.

17. The apparatus of claim **13** further comprising a pad carrying the at least one formation evaluation sensor.

18. The apparatus of claim **13** further comprising an extension device

for moving the pad from a retracted position to an extended position wherein the pad makes contact with the formation, said device selected from the group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.

19. The apparatus of claim **13** wherein the parameter of interest is selected from the set consisting of: (i) resistivity of the formation, (ii) density of the formation, (iii) compressional wave velocity of the formation, (iv) fast shear wave velocity of the formation, (v) slow shear wave velocity of the formation, (vi) dip of the formation, and (vii) radioactivity of the formation, and (viii) resistivity image of the borehole.

20. The apparatus of claim **13** further comprising at least one stabilizer coupled to the housing for stabilizing the apparatus during drilling operations, and wherein the at least one formation evaluation sensor is carried by the at least one stabilizer.

21. A method of determining a parameter of interest of a formation surrounding a borehole while drilling the borehole, comprising:

(a) conveying in the borehole a drilling assembly including a drillbit for drilling the borehole and a formation evaluation apparatus including a rotatable housing;

(b) making measurements related to a parameter of interest of

the formation with a formation evaluation sensor, wherein the sensor is coupled to a pad carried on a selectable member on the outside of the housing, the selectable member being a rotating member when not selected and a substantially non-rotating member when selected; and

(c) processing the measurements from the formation evaluation sensor in a processor on the housing to determine the parameter of interest.

22. The method of claim **21** further comprising obtaining directional information from a directional sensor coupled to the housing and using the directional information in the processor.

23. The method of claim **22** wherein the processing includes computing a rate of penetration of the drilling tool.

24. The method of claim **22** wherein the parameter of interest is a resistivity image of the borehole.

25. The method of claim **21** wherein the drilling assembly is conveyed on a drilling tubular selected from: (i) a drillstring, and (ii) coiled tubing.

26. The method of claim **21** further comprising operating an extension

device for moving the pad from a retracted position to an extended position wherein the pad makes contact with the formation, said extension device selected from the group consisting of: (i) hydraulically operated, (ii) spring operated, and (iii) electrically operated.

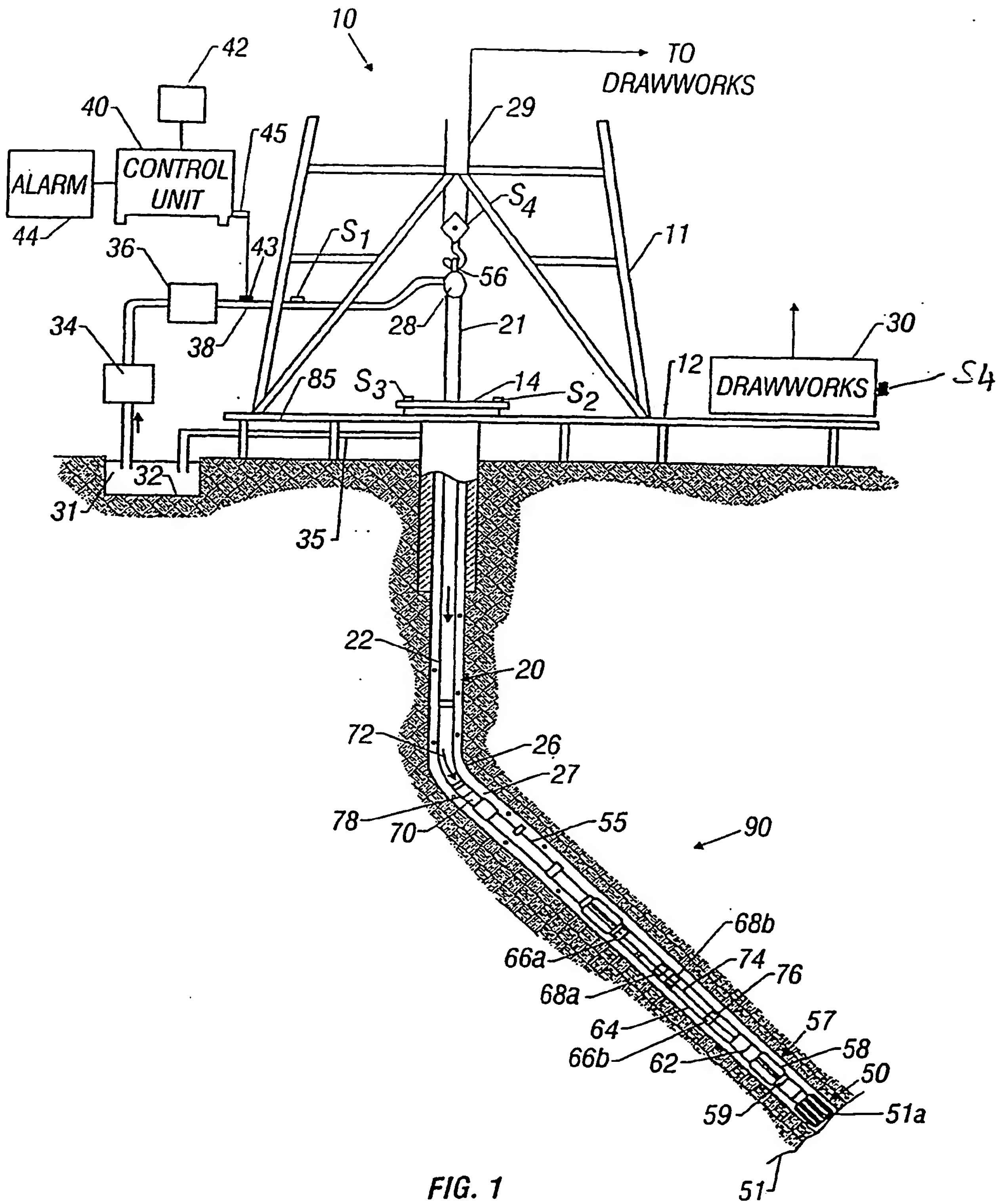
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FIG. 1

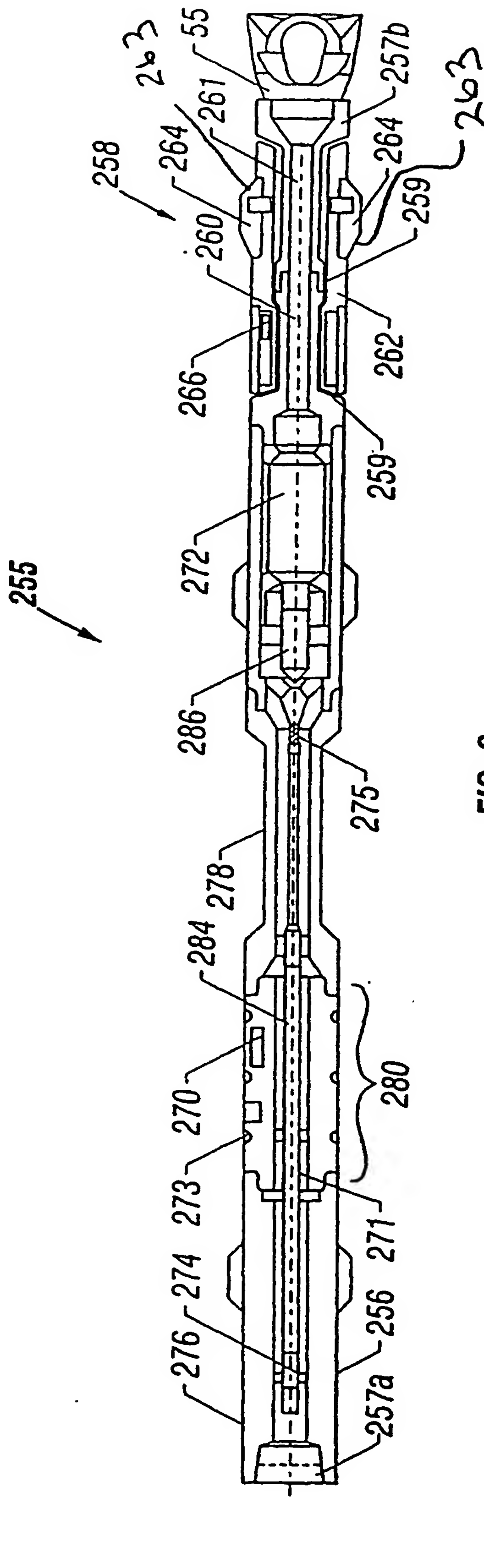
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FIG. 2

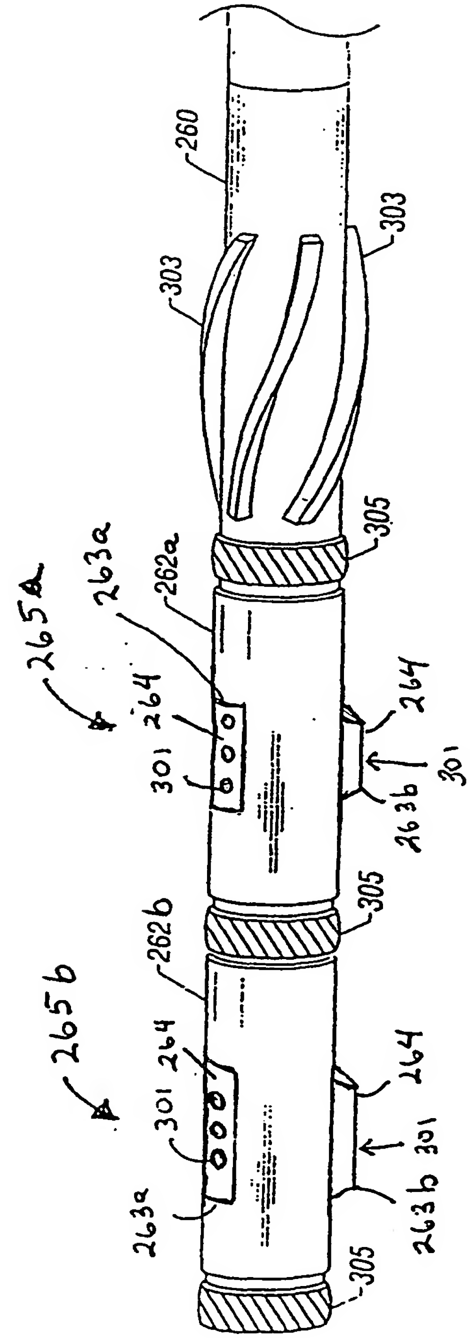
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FIG 3A

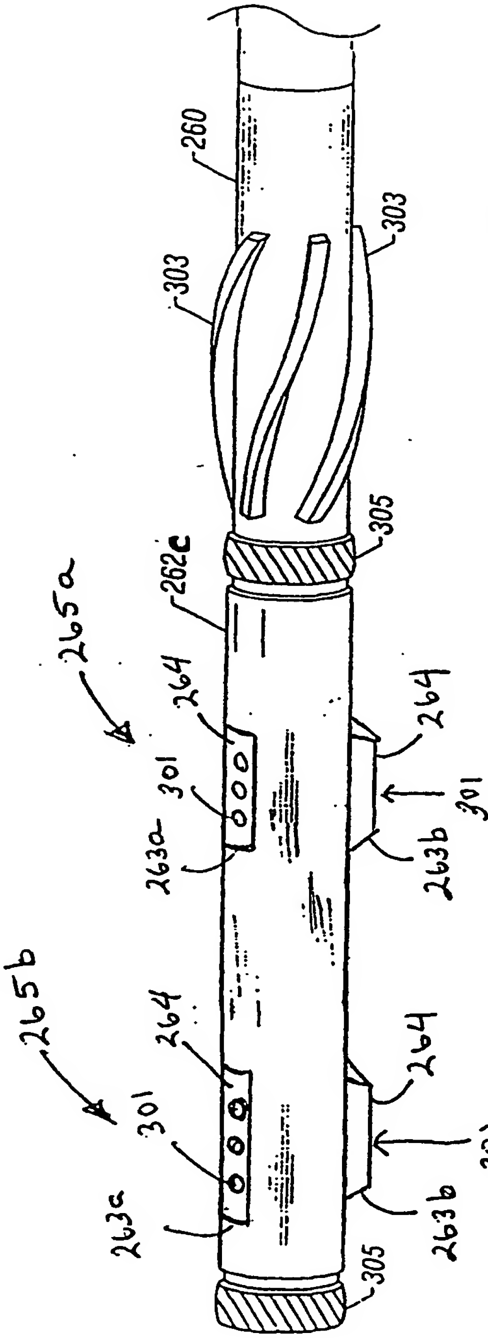
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FIG 3B

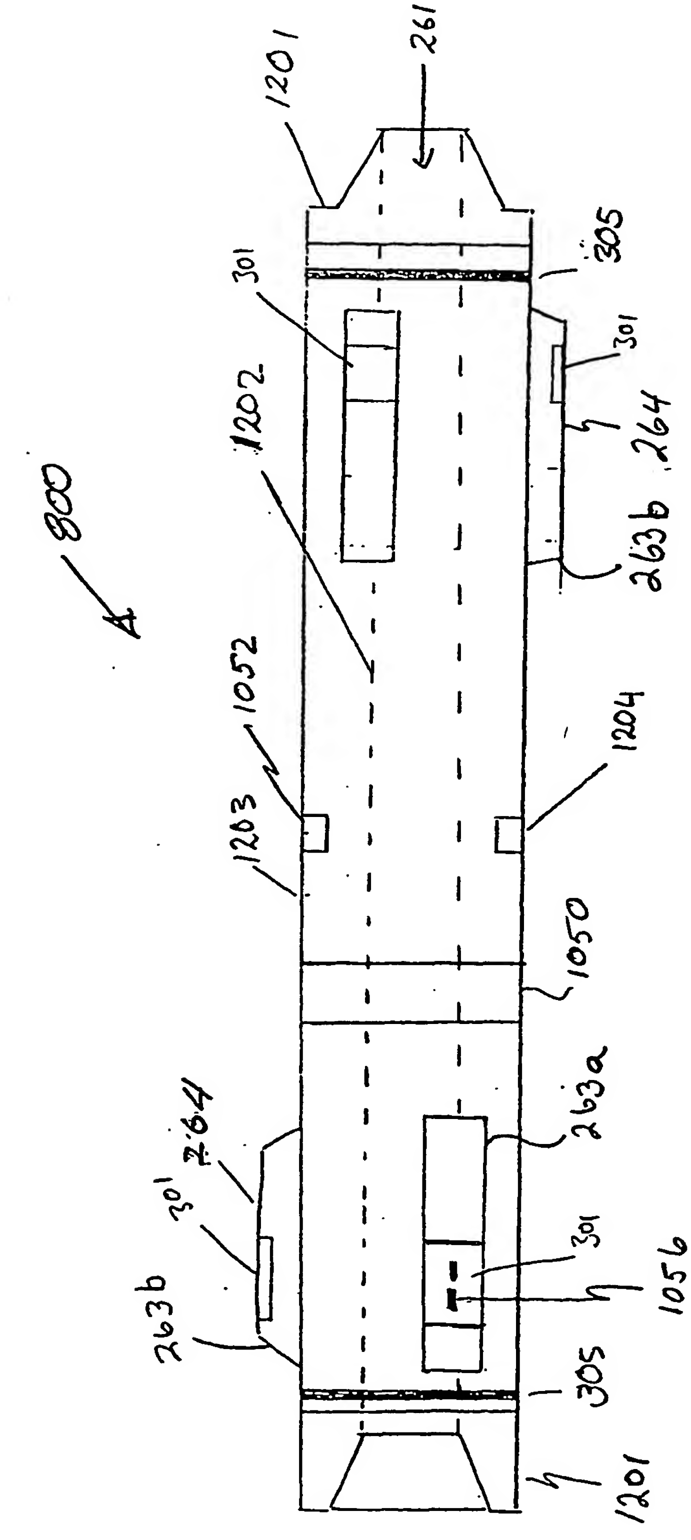
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Fig 3C

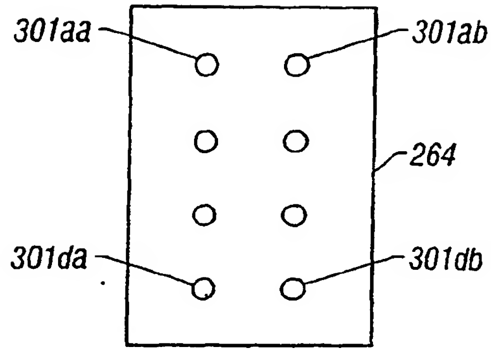


FIG. 3D

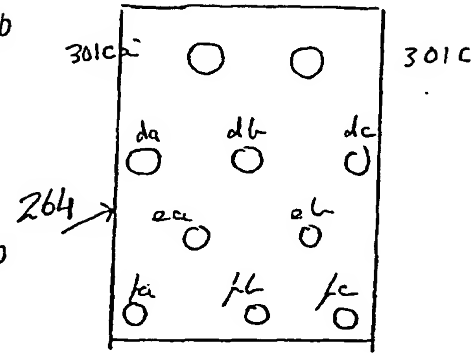


FIG. 3E

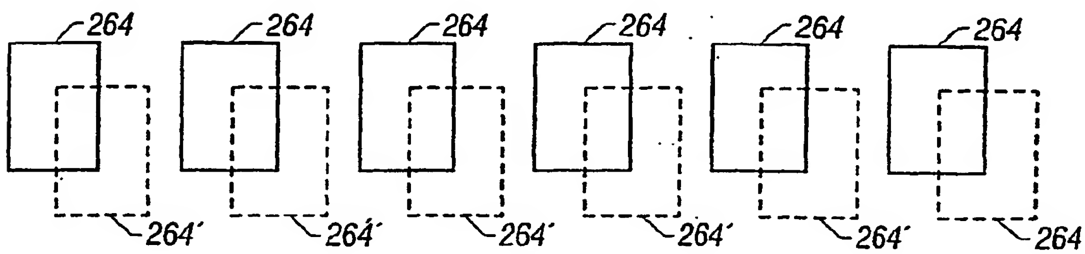
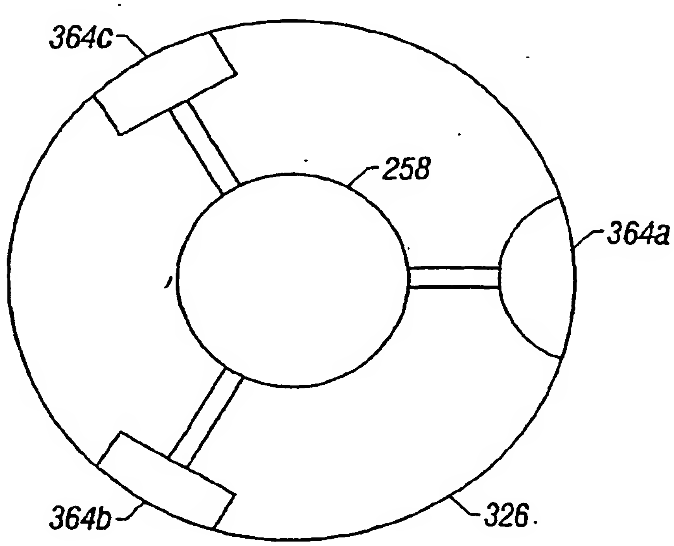


FIG. 3F



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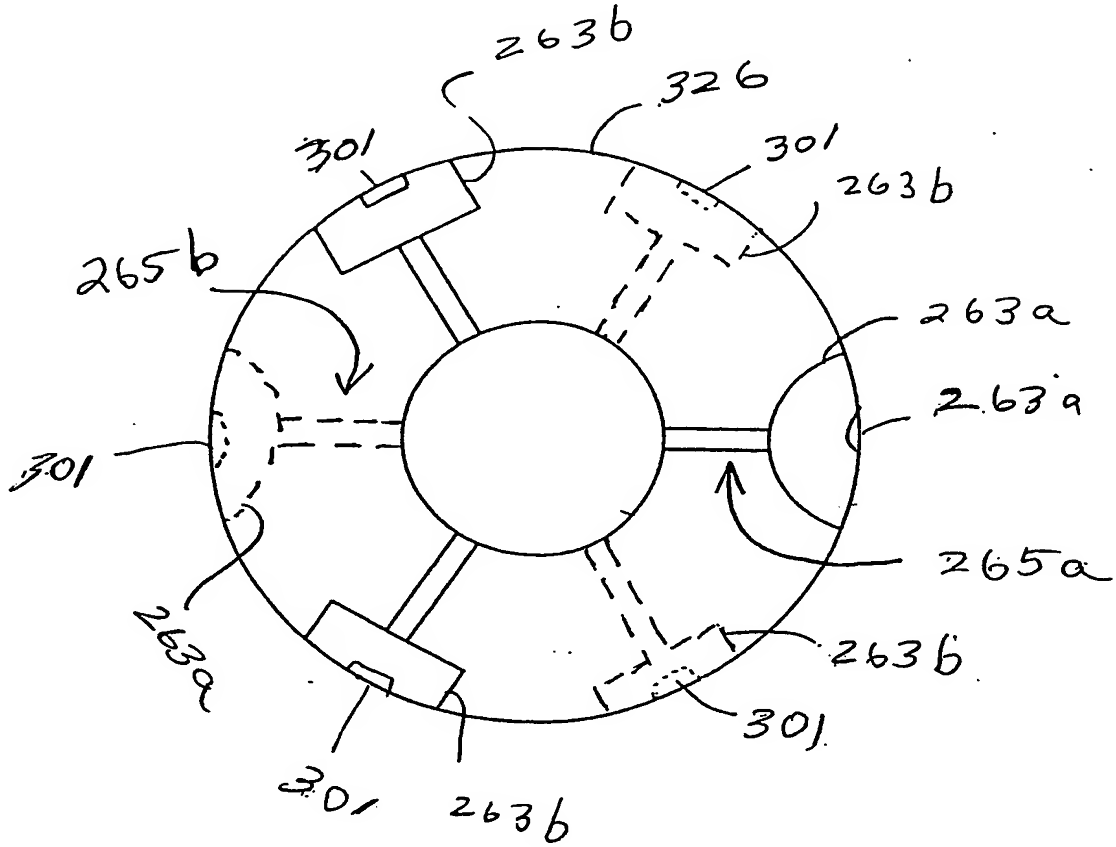
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FIG 3H

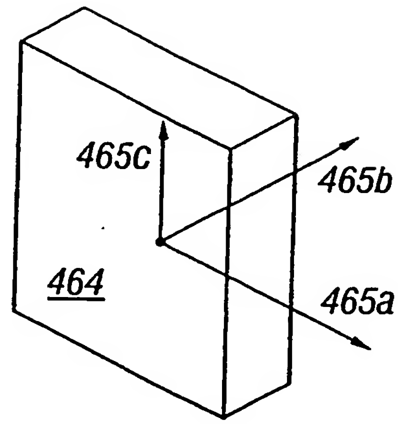
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FIG. 3I

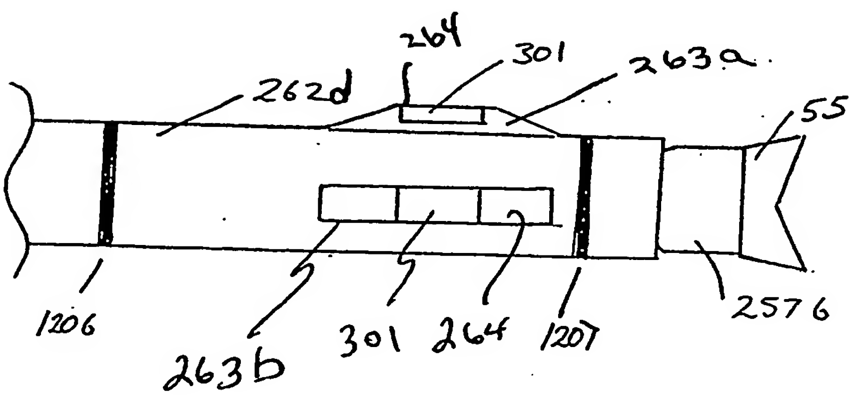
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FIG. 3J

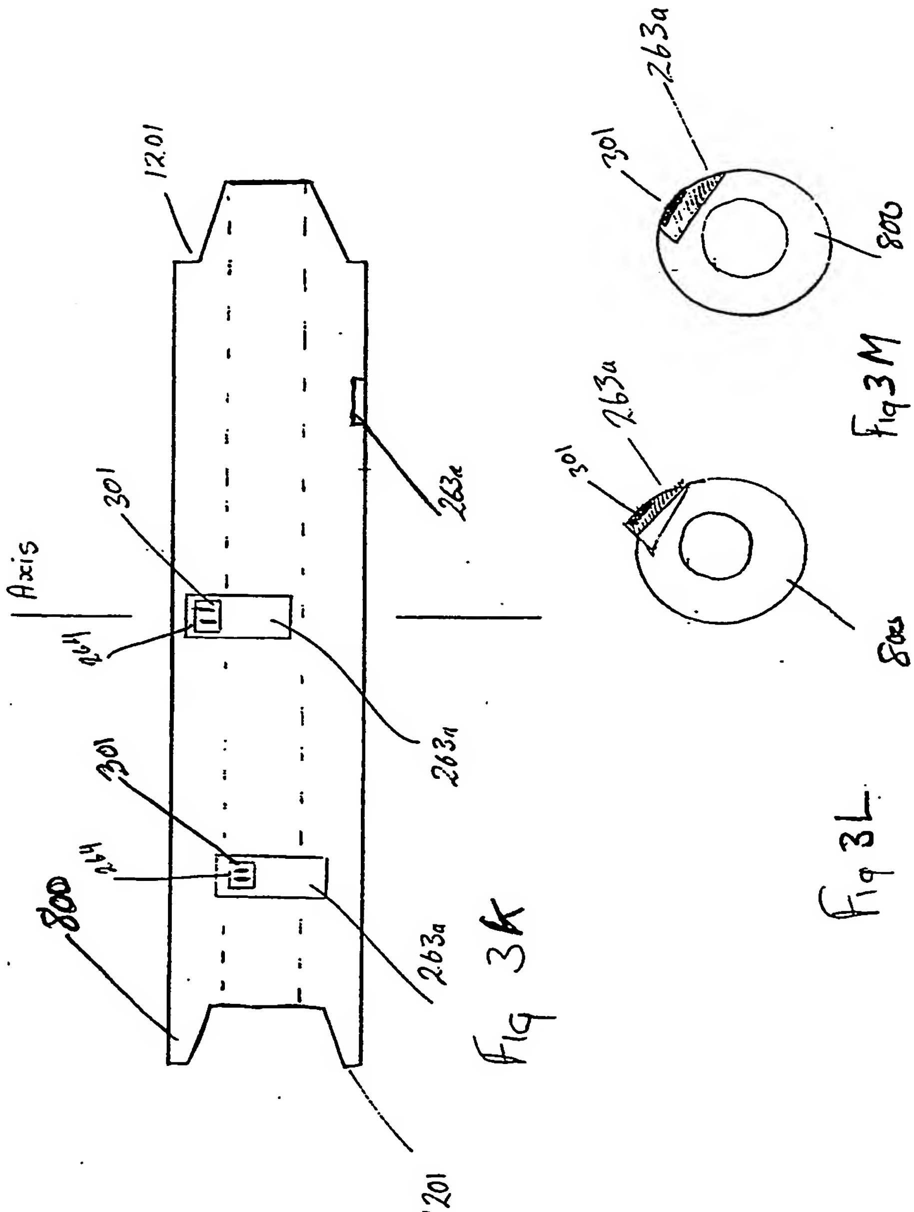


Fig 3K

Fig 3L

Fig 3M

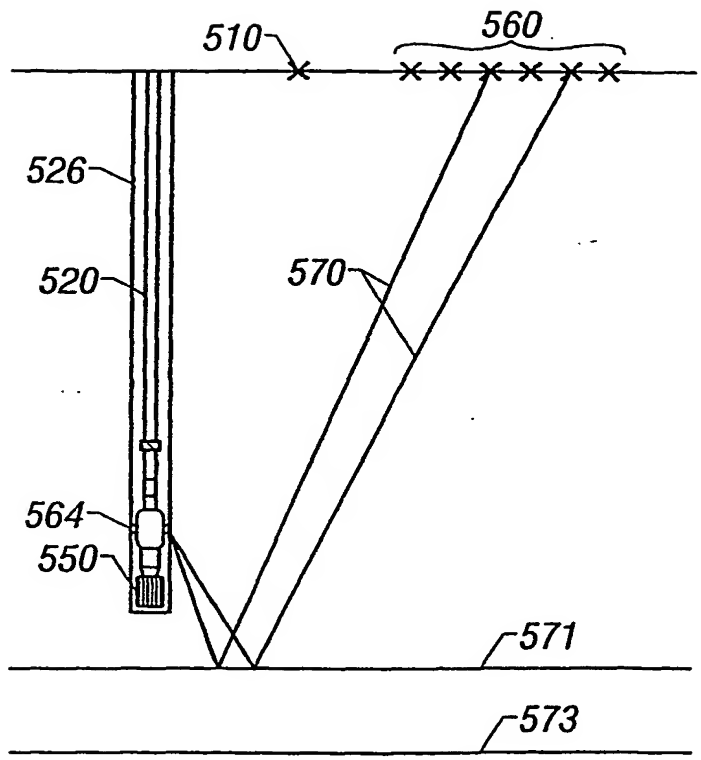


FIG. 4

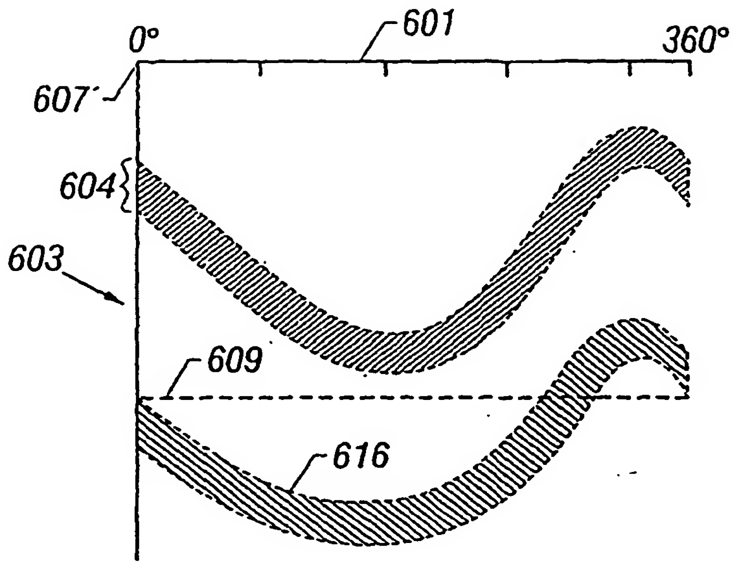


FIG. 5A

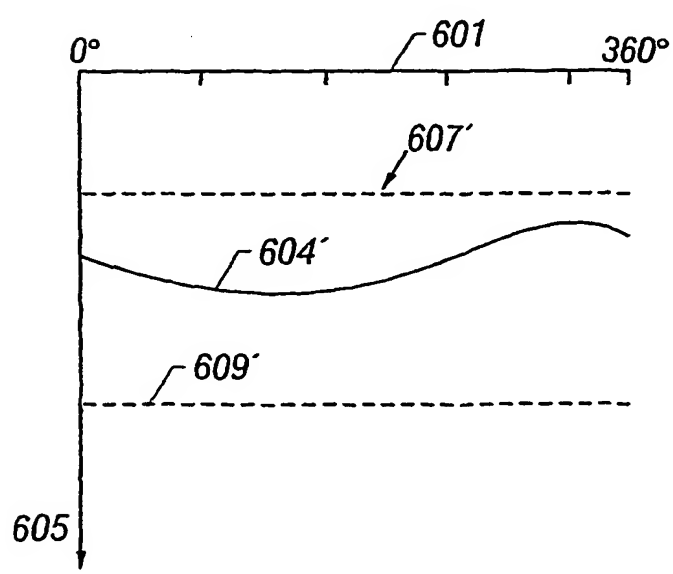
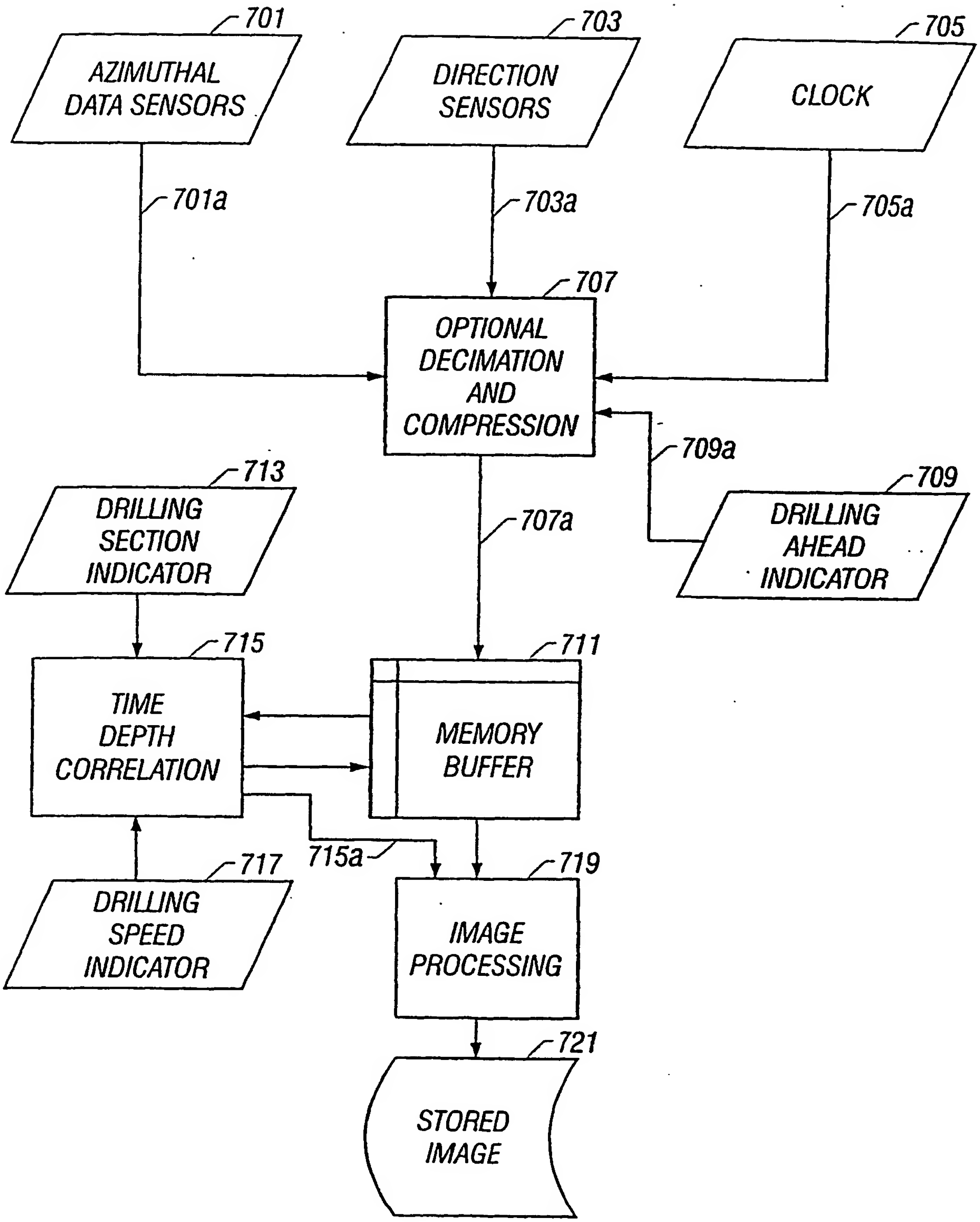


FIG. 5B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DRILLING AHEAD INDICATOR
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FIG. 6A

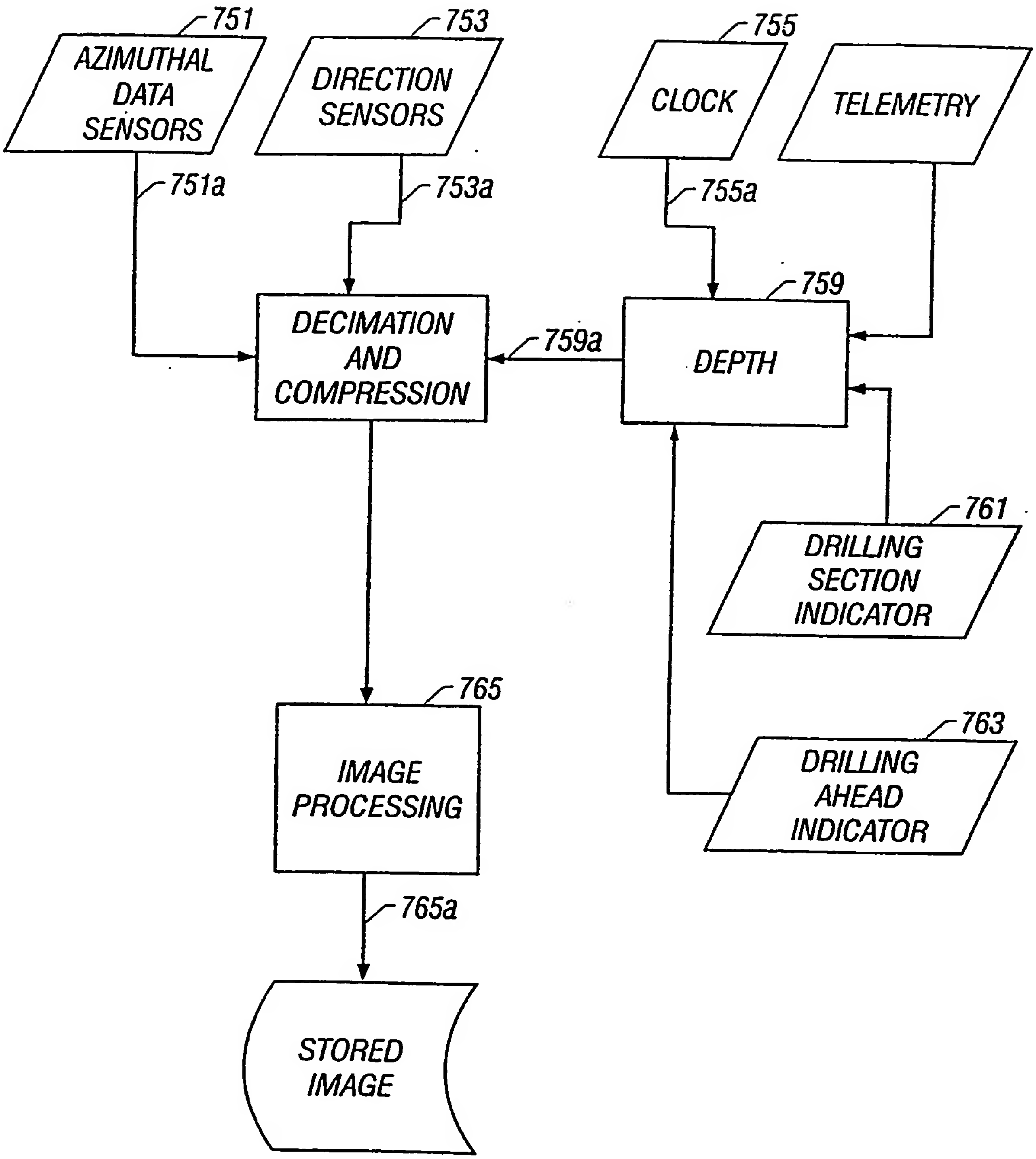
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FIG. 6B

INTERNATIONAL SEARCH REPORT

International Application No
PCT/US 01/44837

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 G01V11/00

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 G01V E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, WPI Data, PAJ

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	WO 99 45234 A (BAKER HUGHES INC) 10 September 1999 (1999-09-10) page 25, line 16 -page 27, line 22	1-12
A	GB 2 334 982 A (BAKER HUGHES INC) 8 September 1999 (1999-09-08)	1-12
X	page 10, line 5 -page 11, line 3 page 13, line 18 - line 21 page 26, line 21 - line 22 claims 1-6,14-21,24-29	13-26
A	US 5 836 406 A (SCHUH FRANK J) 17 November 1998 (1998-11-17) column 4, line 1 - line 48; figures 4A,4B,4C,4D	1

-/--

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

° Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

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"O" document referring to an oral disclosure, use, exhibition or other means

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"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

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"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
9 July 2002	23/07/2002

Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL – 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Häusser, T

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 4 904 865 A (MEISNER JAMES E ET AL) 27 February 1990 (1990-02-27) column 2, line 3 - line 18 -----	7

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/US 01/44837

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